Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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Prediction of power, energy and hydrogen demand in a zero-emission port

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås
Co-supervisor: Aurora Fosli Flataker and Jonatan Klemets

June 2023

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Abstract

Norway aims to achieve a zero-emission maritime fleet by 2050. To reach this goal it is predicted that shore power and green alternatives such as full-electric, plug-in hybrid electric, hydrogen, ammonia and methanol are implemented. All the mentioned options require electricity from renewable sources to be considered emission-free. However, a detailed power analysis regarding a zero-emission port is still not developed for the maritime sector. Therefore in this master thesis, a model is developed which considers the use of different green alternatives to compute the future energy, power, and hydrogen demand at a zero-emission port.

The developed model consists of three parts "Load Model", "Electricity Price Model", and "Optimization Model" and is designed in a generalized manner so that it can be applied to all ports in Norway. The "Load Model" determines the total loads included in a zero-emission port, considering hydrogen, shore power, and charge power to full-electric and plug-in hybrid ships per hour throughout the year. In addition, the energy production from local solar panels is included. The "Optimization Model" consists of two optimization problems, which utilize the calculated loads, in addition to the electricity prices and grid tariffs to estimate an optimal production of hydrogen based on minimizing annual costs of operation. The "Optimal operation" optimizes the operation cost in a port where the capacities of electrolysis, transformer and hydrogen storage are limited, while "Operation and investment optimization" includes finding the optimal sizes of electrolysis, transformer and hydrogen storage for a port by minimizing the investment cost in addition to the operation cost.

In this master thesis, the port of Oslo is utilized as a case study to analyze the future power, energy and hydrogen demand for six different fuel mix scenarios. Furthermore, a sensitivity analysis is conducted to test the impact of the different system parameters. Summarizing the results, the implementation of shore power for all ships is estimated to require approximately 7 GWh for a year with a power peak reaching 3 MW. This implementation has the potential to reduce CO2 emissions in ports by approximately 4505 tons per year. Furthermore, in a scenario where all ships are either "Green hybrids" or fueled with hydrogen, the total hydrogen demand for a year is calculated to be 18260 tons with a total energy demand of 923 GWh and a power peak reaching 170 MW. This implementation has the potential to reduce CO2 emissions in ports by approximately 215422 tons of CO2 per year. However, the predicted power demand is 4.7 times greater than the existing transformer capacity in the port of Oslo. This indicates that the capacity in both the transformers and cables needs to be renewed to handle a higher power demand in the future. Furthermore, the sensitivity analysis of this master thesis presents that the day-ahead prices of former years as well as a higher investment cost of electrolysis can reduce the simulated power peaks.

The results obtained from this study contribute to providing an overview of the approximate total energy, power, and hydrogen demand that may emerge in the future. The primary purpose of this study is to raise awareness among stakeholders and industry participants regarding the projected demand, enabling them to plan and adapt their infrastructure and capacities accordingly. By doing so, they can better prepare for the anticipated changes and requirements in the maritime sector.

Sammendrag

Norge har som mål å oppnå en utslippsfri maritim flåte innen 2050. For å nå dette målet må ny teknologi og alternative drivstoff bli implementert i den maritime sektoren. Noen av de foreslåtte teknologiene er batteri til full elektrisk og hybride skip, samt benytte seg av de utslippsfrie drivstoffene hydrogen, ammonium og metanol. Om hydrogen, ammonium og metanol skal kunne regnes som 100 % utslippsfrie må de produseres ved bruk av strøm fra fornybare kilder gjennom elektrolyse. Disse alternativene vil kreve mye strøm og det er viktig å gjennomføre gode analyser som kan forutse hvordan det økende behovet vil påvirke kraftnettet slik det er i dag. På grunn av mye usikkerhet i den maritime sektor finnes det ingen gode analyseverktøy for å beregne det kommende kraftbehovet til sektoren. Derfor er det i denne masteroppgaven utviklet en modell som kan beregne fremtidige energi-, effekt- og hydrogenbehov for en valgfri havn som implementerer en eller flere av de nevnte teknologiene og nullutslippsdrivstoffene.

Modellen består av tre deler: "Lastmodell", "Strømprismodell" og "Optimaliseringsmodell", og er laget slik at den kan brukes på alle havner i Norge. Lastmodellen beregner timesbehovet for hydrogen, landstrøm og ladestrøm for de ulike skipstypene som er i havn. I tillegg er produksjonen fra lokale solcellepaneler inkludert. Optimeringsmodellen består av to optimeringsproblemer som begge benytter de beregnede lastbehovene i tillegg til strømpriser og nettleie, for å finne en optimal hydrogenproduksjon basert på å minimere de årlige driftskostnadene. "Driftsoptimalisering" optimaliserer driftskostnadene i en havn der kapasiteten til elektrolyse, transformator og hydrogenlager er begrenset, mens "Drifts- og investeringsoptimalisering" inkluderer å finne de gunstige størrelsene på elektrolyse, transformator og hydrogenlager for en havn ved å minimere investeringskostnadene i tillegg til driftskostnadene.

I denne masteroppgaven brukes Oslo Havn som eksempel for å vise bruksområdene til den utviklede modellen i tillegg til å beregne fremtidig kraft-, energi- og hydrogenbehov for havnen. Det er simulert for seks ulike scenarier med ulik bruk av nullutslipps drivstoff og teknologier. I tillegg er det gjennomført en sensitivitetsanalyse for å teste effekten av de ulike systemparameterne inkludert i modellen. En oppsummering av resultatene viser at implementeringen av landstrøm for alle tilkoblede skip anslås å kreve ca. 7 GWh i løpet av et år, med en effekttopp på 3 MW. Denne implementeringen kan redusere CO2-utslippene i havnene med omtrent 4505 tonn. I et scenario der alle skipene enten er "grønn hybrid" eller bruker hydrogen som drivstoff, er det totale hydrogenbehovet beregnet til 18260 tonn per år med et totalt energibehov på 923 GWh og en effekttopp på 170 MW. Denne implementeringen kan redusere CO2-utslippene i havnene med ca. 215422 tonn. Det beregnede effektbehovet (170 MW) er 4,7 ganger større enn den eksisterende transformatorkapasiteten som befinner seg på Oslo havn. Dette indikerer at kapasiteten i både transformatoren og kabler må fornyes for å kunne håndtere et høyere effektbehov i fremtiden. Videre viser sensitivitetsanalysen i denne masteroppgaven at simuleringer med spotpriser fra tidligere år, samt en større investeringskostnad for elektrolysøren reduserer de simulerte effekttoppene.

Resultatene fra denne studien bidrar til å gi en oversikt over den omtrentlige totale energi-, effekt- og hydrogenetterspørselen som kan oppstå i fremtiden. Hovedformålet med denne studien er derfor å øke bevisstheten blant nettplanleggere og bransjeaktører om den forventede etterspørselen, slik at de kan planlegge og tilpasse infrastrukturen og kapasiteten deretter.

Preface

With great pleasure, I present this master's thesis in Energy and Environmental Engineering for the Department of Electric Energy at the Norwegian University of Science and Technology (NTNU). This thesis represents the learning provided from five years as an engineering student.

I want to thank my supervisor Magnus Korpås and co-supervisors Aurora Fosli Flataker and Jonatan Klemets for great discussions and guidance throughout the development of this master thesis. Special thank you to Jonatan Klemets and SINTEF for generously sharing a Python script used in the ELMAR project, which has significantly enhanced the capabilities of this thesis.

Furthermore, I would like to thank all my classmates and friends from EMIL 18 for all the support and experiences during the last five years. The time in Trondheim would not have been the same without you.

Lastly, I want to extend a special thank you to my family and boyfriend, Sebastian Zieglmeier, for believing in me and supporting me through the work of the master thesis.

Date: 16.06.2023

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List of Abbreviations

AEL Alakine electrolyser.

AIS Automatic Identification System.

CCS Carbon Capture and Storage.

CH2 Compressed Hydrogen.

CO2 Carbon Dioxide.

DSO Distribution System Operators.

EU European Union.

GHG Green House Gas.

GT Gross tonnage.

HFO Heavy Fuel Oil.

IMO International Maritime Organization.

kWh kilowatt hour.

LNG Liquefied Natural Gas.

LOA length overall.

LPG Liquefied Petroleum Gas.

LSFO Low Sulfur Fuel Oil.

MCFC Molten carbon fuel cell.

MDO Marine Diesel Oil.

MEA Membrane Electrode Assembly.

MGO Marine Gas Oil.

NH3 Ammonia.

NOX Nitrogen oxide.

NØS Norwegian economic zone.

PEM Proton Exchange Membrane.

PEMFC Proton exchange membrane fuel cell.

PV Photovoltaic.

SMR Steam Methane Reforming.

SOEC Solid oxide electrolyser.

SOFC Solid oxide fuel cell.

STP Standard Temperature and Pressure.

TSO Transmission System Operators.

VAT Value Added Tax.

Chapter 1

Introduction

1.1 Motivation

This section is based on the work presented in my specialization project report in autumn 2022 [1]. However, some of the paragraphs have been modified to achieve a better formulation and adaption to this master thesis.

In order to be able to achieve the goal of the Paris Agreement, a strict climate policy is necessary in all countries. Therefore the Norwegian government aims to achieve a total reduction of carbon dioxide (CO2) emissions with 50 % to 55 % by 2030 and 90-95 % by 2050, compared to the level of emissions in 1990 [2]. The maritime sector accounts as much as 7.5% of the CO2 emissions registered in Norway [3]. Due to the increasing population, need for goods, and transition from road transport to maritime transport a rising demand of the maritime sector is predicted [4] and thus higher emissions if the fossil fuels are not replaced. Therefore, the International Maritime Organization (IMO) implemented an ambition of reducing the greenhouse gas emissions (GHG) from the maritime sector worldwide by at least 50 % by 2050, compared to 2008 [5]. The Norwegian government is setting higher goals and has announced a climate-neutral Norwegian fleet by 2050 and aims to be a pioneer in developing and implementing the necessary zero-emission fuels [6]. To achieve this goal, new technologies and guidelines are required.

The maritime sector consists of multiple vessels with different sizes, functions, operation patterns, and behavior. These variations lead to the complex and challenging task of finding zero-emission alternatives. Nevertheless, there are already a number of opportunities for the maritime sector and the port to reduce its emissions. The following list gives a brief overview of some promising strategies.

1. **Zero-emission ports**
   To achieve a zero-emission port all the elements of the port causing CO2 emissions must be electrified or replaced with green alternatives.
   - **Shore power**
     Many ships in dock use the combustion engine to produce electricity for their needed heat and lights. Connecting the ships in ports to the power grid can reduce these emissions [7].
   - **Electrification of vehicles on land**
     All vehicles operating in the port transporting goods, such as loaders, trucks, and conveyor belts need to be electrified to reduce emissions [8].
   - **Alternative fuels**
     The maritime sector is developing alternative green fuels and technologies which can reduce the CO2 emission from the sector by up to 100 %. The suggested replacements for fossil fuel are battery/hybrid, hydrogen, ammonia, methanol and biofuels [9] and will in further context of this master thesis be referred to as green alternative fuels.

2. **More efficient ships**
   By reducing the combustion of fuel, the CO2 emission is reduced. It is possible to make ships more efficient by optimizing the hull design, propellers, and engines. In addition, more active use of wind energy can make ships more efficient [9].

3. **Logistics and digitalization**
   Regulation of the vessel's speed, utilization, size, and routes can potentially reduce CO2 emissions by up to 20 % [9].

In order to achieve a climate-neutral maritime sector, the implementation of shore power and green alternative fuels is considered crucial. Both of these initiatives rely on a reliable and robust electricity infrastructure capable of meeting future demand. Typically, power analysis of future energy scenarios are important to transmission grid operators (TSO), distribution grid operators (DSO) and regulatory authorities to be able to reinforce and renew the capacities in the power grid to handle the increasing demand of electricity. Normally, the power analysis (provided by the mentioned grid operators) includes factors such as population growth, housing construction, electrification of the road transportation sector, and well-known industrial or development projects are included. However, there is a noticeable absence of power analyses specifically focused on the electrification of the maritime sector due to uncertainties of the developed alternative fuel technologies. For example, in the power system investigation presented by [10], the forecasts for shore power utilization were deemed too uncertain to serve as a basis for regional grid measures. The power demand for shore power or charge power to a ship is normally way higher than for cars, therefore not including the possible demand of this sector can lead to underestimation of the needed grid reinforcements and flexibility utilization.

Therefore, there is an urgent need for a detailed power and energy analysis regarding the zero-emission maritime sector. Hence, this master's thesis will investigate the impact of implementing shore power for ships and alternative fuels in the maritime sector, focusing on key outcomes such as total energy consumption, power requirements, and hydrogen production through electrolysis.

1.2 Project description and objectives

The objective of this master's thesis can be divided into three main parts. Firstly, it aims to investigate and determine the load demand in a zero-emission port, considering diverse fuel options such as shore power, charge power for full-electric and plug-in hybrids, and hydrogen for ships arriving at the port. This analysis is crucial for understanding the energy requirements and optimizing the usage of sustainable fuels.

The second objective involves utilizing the estimated loads and electricity prices to optimize the production of local green hydrogen, with the goal of minimizing operational costs in the port. This optimization process includes determining optimal sizes for electrolysis, transformers, and hydrogen storage. The developed optimization model can be applied to all ports in Norway, providing a generalized approach for calculating future energy, power, and hydrogen demand in ports. Such analysis is valuable for transmission grid operators (TSO), distribution grid operators (DSO), or regulatory authorities, enabling them to forecast power requirements and enhance the grid infrastructure accordingly. Additionally, the evaluation of total hydrogen demand provides insights for companies involved in green hydrogen production or considering entering the market, helping them understand customer demand and identify market opportunities.

Moreover, the thesis explores the total operation and investment costs associated with different fuel mix scenarios. This assessment offers a comprehensive understanding of the economic feasibility of implementing various fuel options within the port, supporting decision-making processes.

Finally, the developed models in this master thesis are applied to analyze the zero-emission port of Oslo, providing practical insights and recommendations specific to that port's context.

Objectives of this master thesis:

- Provide a model that can be used by analysts for all ports and quay areas of Norway. The goal is that the model can provide information about the total and hourly energy, power, and hydrogen demand considering a zero-emission port.
- Investigate and calculate the load demand per hour in a zero-emission port considering shore power, charge power to full-electric or plug-in hybrid electric ships, and green hydrogen ships. Additionally, analyze the possibility to produce local photovoltaic (PV) power.
  - → As part of this objective, a comprehensive literature review will be conducted to examine the necessary technologies and input data needed for the calculation.
- Develop an optimization model that optimizes the production pattern of green hydrogen through water electrolysis in the port based on hourly and monthly electricity prices while covering all load demand in the port.
  - → As part of this objective, a comprehensive literature review regarding electricity prices will be conducted.
- Develop an optimization model which optimizes both the operation and investment costs in a zero-emission port. This optimization model should in addition to finding the optimal operation pattern of hydrogen production determine the optimal sizes for electrolyser, transformers, and hydrogen storage based on investment costs and capability to cover the demand.
  - → As part of this objective, a comprehensive literature review regarding investment costs of electrolyser, hydrogen storage, and transformer will be investigated.
- Both developed optimization problems should be adaptable for ports whether it exists or not exists transformer capacity, hydrogen storage, and electrolyser in the port.
- Based on the developed models, this master thesis utilizes the port log of Oslo as a case study to calculate the predicted energy, power, and hydrogen demand, considering various scenarios of the fuel mix. Furthermore, the operation and investment costs, in addition to the optimal sizes of electrolysis, hydrogen storage and transformer will be found.
  - → The results will be analyzed and discussed.
  - → The total CO2 reduction by implementing electricity and hydrogen as fuels will be calculated for one scenario.
- Conduct a sensitivity analysis of some of the system parameters. This analysis aims to illustrate the uncertainties and variations of the results presented based on the chosen system parameters.
- The analyses of the results from the port of Oslo will be discussed and compared to other industries and the current capacity in the grid of Oslo.

1.3 Structure of the thesis

This thesis is a continuation of the specialization project in autumn 2022 [1]. Some sections of the chapters 2 and 3 are directly derived from this project report, with varying degrees of modifications and extensions. Hence, some sentences are directly reused without quotes, but most have been modified to achieve a better formulation and adaption to this master thesis.

This master thesis is structured into eleven chapters. The first chapter presents some background motivation and project description for this master's thesis. The rest of the chapters are briefly explained below:

Chapter 2: Theory and Background
This chapter provides information about all the topics and technologies which are used in the

simulation later in the master thesis. It presents the alternative green fuels of the maritime sector, with the primary focus on the technology and prices considering shore power, charge power, and hydrogen production through electrolysis. Furthermore, an overview of the power grid and power market is presented to achieve a better understanding of the future optimization model and analysis.

Chapter 3: Alternative Fuels of the Future
This chapter presents the current and predicted situation of alternative fuels in the maritime sector. The information presented in this chapter should provide the reader with an understanding of the uncertainties in the dividing of alternative fuels through different ship segments. The scenarios for the simulations are based on the discussion provided in this chapter.

Chapter 4: Mathematical Formulation of the Optimization Problem
This chapter presents and explains the mathematical formulation of the two optimization models; "Optimal operation" and "Operation and investment cost optimization" developed in this master thesis. Both optimization models aim to minimize the electricity cost of the zero-emission port while covering the hourly demand of hydrogen, shore power and charge power. Additionally, the second optimization problem includes the investment costs of the electrolyser, hydrogen storage and transformer to obtain the optimal capacities.

Chapter 5: Models and Input Parameters
This chapter presents an overview of the three Python Scripts developed in this master thesis; "Load Model", "Electricity Price Model" and "Optimization Model". The input and output parameters for each of the scripts are presented and discussed.

Chapter 6: Case Study
This chapter presents information and analysis of the port of Oslo which is later used in the simulation as the case study. The analysis of the port log provides a bigger understanding of the results presented in the next chapter.

Chapter 7: Results
The result chapter is mainly divided into two parts. The first part presents proof of the mathematical concept of the two developed optimization models by testing values for different system parameters. The second part utilizes the second optimization model,"Operation and investment cost optimization" for six scenarios considering different fuel mixes. The results are presented in figures and tables.

Chapter 8: Sensitivity Analysis
To explore the impact of various system parameters and input values in the developed models, sensitivity analyses are conducted. This analysis illustrates how some of the input parameters affect the results. The findings presented in the sensitivity analysis are valuable for both understanding of results and for other analyses which will use the developed models.

Chapter 9: Discussion
The discussion in this master's thesis primarily revolves around gaining a deeper understanding of the presented results. Therefore, the uncertainties associated with the findings are thoroughly examined before comparing the data to other industries and assessing the available capacity in the grid.

Chapter 10: Conclusion
The conclusion summarizes the outcome of this master thesis and presents the key contributions to the field.

Chapter 11: Further Work
The further work chapter explains various possibilities that can be incorporated into the developed model of this master thesis to attain more detailed and complex results.

Chapter 2

Theory and Background

This chapter provides necessary theoretical and background information concerning the technology and input parameters utilized in the developed model of this master thesis. It begins by introducing green alternative fuels in the maritime sector. However, since this master thesis aims to calculate the future energy, power and hydrogen demand for a zero-emission port the technological background will mainly focus on the components with an impact on these processes. Furthermore, information regarding the power grid and energy market is presented to gain insight into the challenges currently faced, particularly as the electricity demand continues to rise. The concept of a duration curve is also explained, which will be utilized to present the plots and results obtained in this study. Furthermore, the theory regarding the measurement and calculation of power produced from photovoltaic (PV) systems is described, as it is assumed that PV implementation will be part of the future port [8]. Lastly, a literature review of the investment costs associated with electrolysis, hydrogen storage, and transformers has been conducted. These parameters will serve as the input data for the optimization model developed in this thesis.

2.1 Green fuels in the maritime sector

To reach the goal of a zero-emission maritime sector new green fuels need to replace the fossil fuels such as marine gas oil (MGO), marine diesel oil (MDO) and heavy fuel oil (HFO), which are in use today. There are some challenges regarding replacing fossil fuels with new green fuels, which are mainly based on two reasons; the technology and the economy. First, the maritime sector consists of multiple variations in the ship's size, function, weight, and route of travel. Based on these unique parameters, the ships require different amounts of energy. To replace the fossil fuel, the green fuel needs to have a high enough energy density to propulsion the ship. Secondly, the storage onboard the ship has to be feasible for the purpose of the ship. Meaning, the storage can not occupy the room meant for the goods to distribute or be so heavy that the propulsion efficiency gets too low. Furthermore, the green fuel is required safe to operate. Lastly, the new technology and infrastructure connected to replacing fossil fuels are expensive. Therefore, green fuel will not fully be implemented before the prices are competitive or the political goals become more strict and the CO2 fee increases [9].

Nevertheless, the green fuel under development today can mainly be divided into three categories: Biofuel, electricity, and hydrogen. Electricity is included in the term "green fuel" for this master thesis even though it is not technically considered a fuel. Table 2.1 presents some predicted fuels belonging to one of the mentioned groups [11].

Table 2.1: Overview of the various green fuels currently under development

Bio-fuel	Green hydrogen	Pure electricity
bio-MGo	green ammonia	full-electric
bio-LNG	green methanol	plug-in hybrid
bio-methanol		

This master thesis focuses on the future energy, power and hydrogen demand of the maritime sector. Therefore, the main focus of this study is to describe the technology and theory considering the fuels regarding green hydrogen and pure electricity. Bio-fuel is only short-mentioned to get a brief overview of the possibilities.

2.1.1 Biofuels

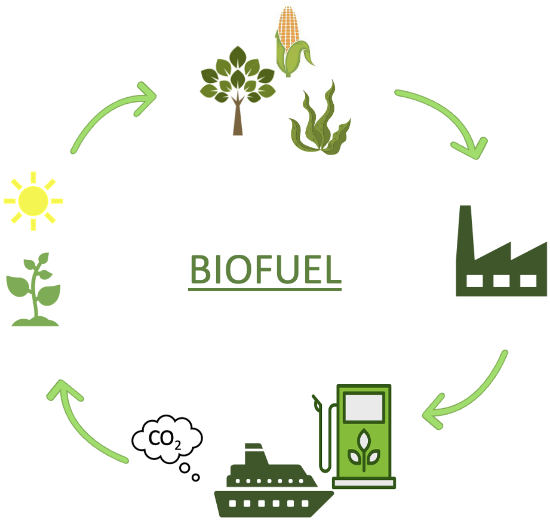


Figure 2.1: Biofuel

Biofuel is a green fuel derived from biological sources such as plants and animal waste. These biological sources are classified into four generations, as illustrated in 2.2, with the first generation being utilized today. However, the use of food crops as fuel has drawn significant criticism. Consequently, the second generation, which involves biofuels produced from waste materials or considered non-edible, is predicted to be implemented from now on and especially in the maritime sector. Considering algal biomass and gen modification in biomass is also under development [11].

Within the maritime industry, bio-MGO, bio-LNG, and bio-methanol are considered the most promising biofuel options. A notable advantage of biofuels lies in their possibility to blend with already existing conventional fuel and use the same engines installed in ships. However, the production processes for second-generation biofuels have not yet reached the level of maturity required for large-scale production. Biofuels are generally recognized as a superior alternative to fossil fuels due to their capacity to reduce greenhouse gas (GHG) emissions. Nevertheless, when burned, biofuels still emit some CO2 gas [11].

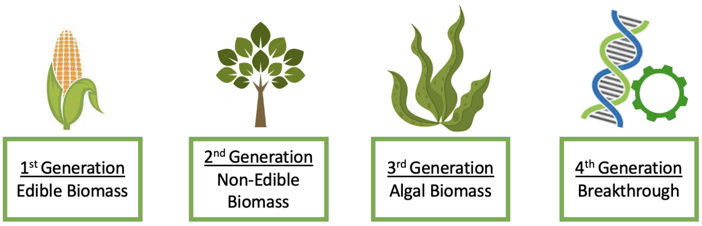


Figure 2.2: The four generations of biomass

2.1.2 Hydrogen

This section will present the technology of hydrogen production, hydrogen storage on land and onboard ships and fuel cells. The energy density and efficiency are analyzed for all mentioned parts.

Hydrogen has the potential to play an important role to achieve a zero-emission maritime sector. Hydrogen is often categorized by color, representing how it is produced. The three most common hydrogen categories are gray, blue, and green. Gray and blue hydrogen are both produced from fossil fuels, mainly natural gas, which causes a high carbon footprint [12]. However, blue hydrogen includes carbon capture and storage (CCS) to mitigate CO2 and therefore reduce the emission. Green hydrogen is produced through water electrolysis, where an electric current is passed through water (H2O), splitting it into hydrogen (H2) and oxygen (O2). The electricity used for this electrolysis is generated from renewable sources such as solar, wind, or hydroelectric power, and is therefore considered to have a CO2 emission close to zero.

According to [12], a wide range of colors, including turquoise, yellow, purple, pink, red, aqua, and white, are also utilized to classify various methods of hydrogen production. In this master thesis, the production of hydrogen through electrolysis will be assumed to be green because the Norwegian grid mix consists of 98% renewable energy [13]. As a result, the definition in this paper will employ green hydrogen when the electricity is bought from the power grid.

Figure 2.3 illustrates the hydrogen chain from energy production to the propulsion of the ship considering green hydrogen through water electrolysis. The components included between the electrolyser and hydrogen storage and bunker, such as compressors and other auxiliaries are not investigated in this master thesis.

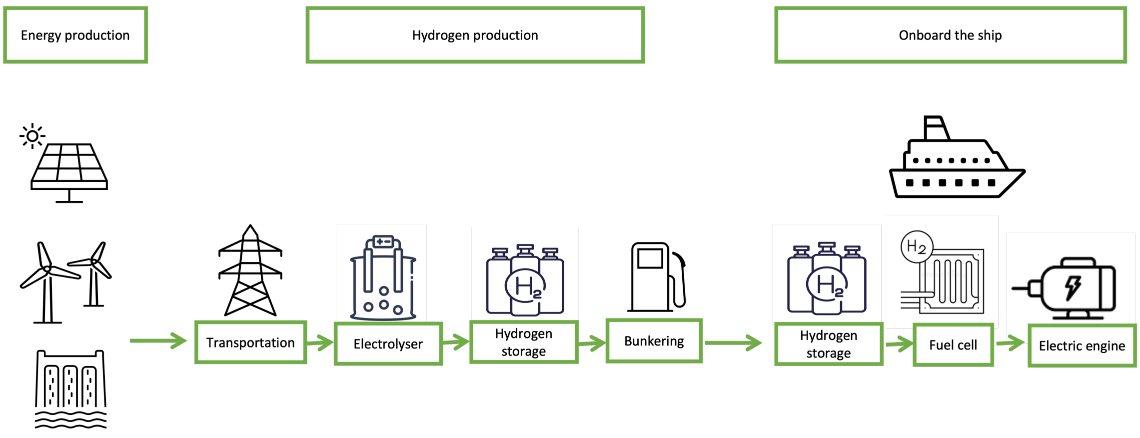


Figure 2.3: Illustration of the hydrogen chain from energy production to the propulsion of the ship considering green hydrogen through water electrolysis

General facts about hydrogen

The following paragraphs within this subsection 2.1.2 are based on my work done in the specialization project in autumn 2022 [1]. However, some of the paragraphs have been modified to achieve a better formulation. In addition, all figures are new and self-made.

"Hydrogen is the first and lightest element in the periodic table. This provides some advantages and disadvantages of the element. First of all, hydrogen has an exceptionally high specific energy density. This indicates that more energy can be stored in the fuel. The lower and higher heat value of hydrogen equal 120 MJ/kg and 142 MJ/kg, respectively [14]. Compared to conventional fuels, these numbers are 2.5-3 times greater [14]. This provides some benefits for situations where weight is a problem. On the other side, hydrogen is an element that combines easily with other elements. Therefore, it requires some energy to produce hydrogen in its pure form. The cost, complexity, efficiency, and safety regulations are some drawbacks of hydrogen [15]. The density of hydrogen gas equals 0.082 kg/m^3 at standard temperature and pressure (STP), which is 12 times less than air [14]. This means that the storage of hydrogen requires more volume than other fuels" [1] (pp.12).

Electrolyser

Production of green hydrogen by using electrolysis is not a new technology. However, because of high prices for green hydrogen, the use of natural gas and steam methane reforming (SMR) overtook the market [16]. To be able to reach the climate goals, the production and development of green hydrogen have again been raised. Green hydrogen is produced with the use of a water electrolyzer, where the water molecules are split into hydrogen and oxygen gas by the use of electricity. The chemical formula is [17]:

$$Electric\ energy + H_2O(l) \rightarrow H_2(g) + 0.5O_2(g) \tag{2.1}$$

The three most common water electrolysis technologies are; polymer electrolyte membrane electrolysis (PEM), alkaline (AEL), and solid oxide electrolyzer cell (SOEC) [17]. Figure 2.4 illustrates a PEM electrolysis, and the chemical reactions for the three mentioned electrolysis are presented in table 2.2.

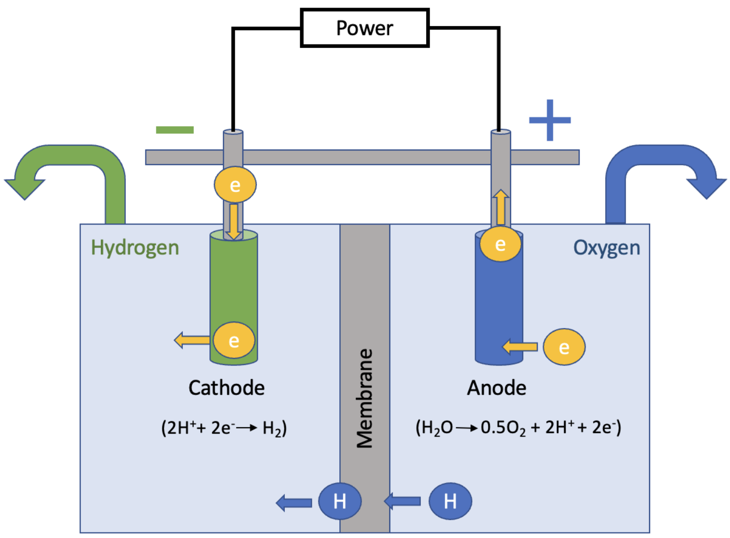


Figure 2.4: PEM electrolysis with the chemical reaction on cathode and anode

Table 2.2: Chemical reactions for the different electrolysis processes [17]

Alkaline	PEM	SOEC
$Anode : 2OH^- \rightarrow H_2O + 0.5O_2 + 2e^-$ $Cathode : 2H_2O + 2e^- \rightarrow H_2 + 2OH^-$ $Global : H_2O \rightarrow H_2 + 0.5O_2$	$Anode : H_2O \rightarrow 0.5O_2 + 2H^+ + 2e^-$ $Cathode : 2H^+ + 2e^- \rightarrow H_2$ $Global : H_2O \rightarrow H_2 + 0.5O_2$	$Anode : O^{2-} \rightarrow 0.5O_2 + 2e^-$ $Cathode : H_2O + 2e^- \rightarrow H_2 + O^{2-}$ $Global : H_2O \rightarrow H_2 + 0.5O_2$

Alkaline electrolysis is a well-established method that has been in use in industrial applications for over a century. This electrolysis process involves the use of an alkaline solution, commonly potassium hydroxide (KOH) or sodium hydroxide (NaOH), as the electrolyte. At the cathode side, the alkaline solution is reduced, leading to the generation of hydrogen gas (H_2) and hydroxide ions (OH^-). Simultaneously, at the anode, oxygen gas (O_2) is evolved through the oxidation of water. One characteristic of alkaline electrolysis is its operation at low current densities, typically around 2 kA/m². This low current density requirement results in the need for larger electrolysis systems to accommodate the desired hydrogen production rate. However, this drawback is often offset by the relatively low cost associated with alkaline electrolysis, as it does not require the use of expensive or noble metals as catalysts [14].

Polymer electrolyte membrane PEM electrolysis, on the other hand, employs a membrane electrode assembly MEA to separate the cathode and anode compartments [18], as illustarted in figure 2.4. PEM electrolysis offers several advantages, including rapid start-up and shutdown times and the ability to handle significant load variations. Moreover, PEM electrolysis can operate at high pressures of up to 350 bar, which is substantially higher than the 30 bar limit of alkaline electrolyzers [18] [1].

The solid oxide electrolyzer cell SOEC represents a technology that utilizes a solid oxide material as an electrolyte. Although this technology still is in the early stages of development, capabilities such as high current densities, operating at elevated temperatures, and high electrical efficiency are achieved.

Table 2.3 provides a summary of the characteristics of different water electrolysis systems [19]. Both PEM and alkaline electrolysis are commercially available, while SOEC is still in the development phase. Alkaline electrolyzers offer advantages in terms of efficiency, technological maturity, and low investment costs. On the other hand, PEM electrolysis possesses superior flexibility, which is essential for accommodating the future demands of the flexibility market where the storage of energy from diverse renewable sources is crucial. Additionally, PEM electrolysis can function as fuel cells, allowing for power generation that can be fed back into the grid as needed. SOEC electrolysis, which can also be used as fuel cells, offers the highest efficiency but have shorter lifetimes and higher investment costs [19].

Table 2.3: Characteristics for an alkaline, PEM and SOEC electrolyser [19]

		Alkaline	**PEM**	**SOEC**
	Development status	Commercial	Commercial	Demonstration
Operating conditions	Temperature (°C)	70-90	50-80	700-850
	Pressure (bar)	30	<70	1
Cost parameters	Investment cost ($/kW)	6000	1000	>20000
	Efficiencies based on LHV	0.42-0.67	0.40-0.67	0.67-0.83
Flexibility	Start-up	1-10 min	1 sec-5 min	-
	Ramp up/down	0.2-20 % per second	100 % per second	-
	Shutdown	1-10 min	seconds	-

Determining the precise efficiencies of an electrolyser is challenging due to various factors, including size, design variations, and developmental aspects.[20] present that the system efficiency for alkaline and PEM electrolyser can reach 76.5% and 75%, respectively. These efficiencies values exceed the ranges presented in 2.3 and highlight the uncertainties associated with electrolysis efficiency.

Electrolyser Capacity

In order to gain a better understanding of the potential capacity of electrolysis systems, a tabular overview has been provided outlining several planned large-scale electrolysis plants. Among these plants, the largest is projected to have a capacity of up to 500 MW and be constructed in Sweden by the year 2025. Furthermore, it is expected that several electrolysers with a capacity of 200 MW will be installed this year [21].

Table 2.4: Overview of future large-scale electrolyser plants [21]

Company	Electrolyser capacity [MW]	Planned start of operation	Location
Thyssenkrupp Uhde Chlorine Engineers GmbH	88	2023	Québec, Canada
Siemens AG - Air liquid GmbH	200	2023	Normandy, France
Iberdrola – nel ASA	200	2023	Puertollano, Spain
Shell	200	2023	Rotterdam, The Netherlands
Vattenfall – Shell Global - Mitsubishi Heavy Industries	100	2025	Hamburg, Germany
Vatenfall GmbH – Preem Petroleum AB	200–500	2025	Lysekil, Sweden

Hydrogen storage and safety

Hydrogen storage is a critical aspect of utilizing hydrogen as a fuel in both land-based and maritime applications. Various methods are available for storing hydrogen, including compressed hydrogen gas, liquid hydrogen, and chemical conversion to compounds like ammonia (NH3) or methanol (CH3OH), as shown in Figure 2.5. However, the safe storage of hydrogen presents some challenges, particularly in the context of vessel operations. Hydrogen is highly flammable, and any leakage or mishandling can potentially lead to explosions or fires. Furthermore, the chosen storage method must be competitive with fossil fuel options in terms of factors such as size, weight, and energy density. Finding efficient and safe hydrogen storage solutions is crucial for the integration of hydrogen as a fuel in the maritime industry.

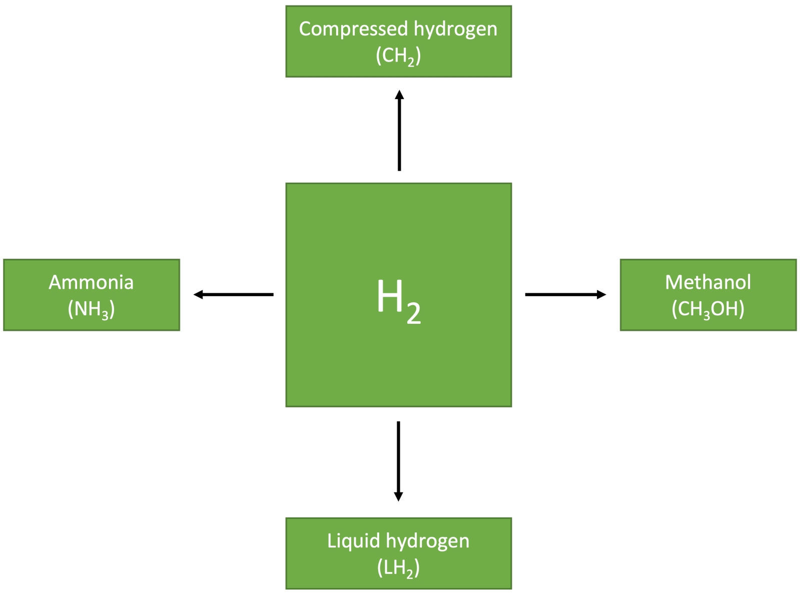


Figure 2.5: Possible fuels from hydrogen

Compressed hydrogen

Compressed hydrogen (CH2) storage typically involves the compression of hydrogen gas at 350 or 700 bar. However, it is important to note that the density of hydrogen at these pressures is relatively low, approximately 23 kg/m^3 at 350 bar and 38 kg/m^3 at 700 bar. Consequently, storing large volumes of compressed hydrogen requires significant space resulting in increased weight and volume. Specifically, for storage onboard ships are size and weight of the storage important. To mitigate these limitations, ships can use compressed hydrogen storage at 350 bar. A pressure of 700 bar might be used for vessels requiring small hydrogen volumes. As compressed hydrogen is stored and utilized in the gas phase, the storage system onboard the ship is comparatively less complex than systems used for liquid hydrogen and ammonia storage [14].

Liquid hydrogen
For the hydrogen gas to convert to liquid form a temperature of -253 Celsius is required. At this temperature, the density of liquid hydrogen is approximately 71 kg/m^3 [4], which is significantly higher than that of compressed hydrogen at standard temperature and pressure. High energy density, allowing to store more hydrogen in a smaller volume. However, utilizing liquid hydrogen as a storage option poses several challenges. First, effective tanks and fuel system insulation are necessary to prevent the liquid hydrogen from boiling off which adds complexity to the storage system. Moreover, maintaining the extremely low temperature in the tanks requires a substantial amount of energy. The energy demand required to keep the low temperature of -253 Celsius is around 25-30 % of the original energy amount [22]. This energy-intensive process contributes to the higher cost associated with liquid hydrogen storage compared to compressed hydrogen. Historically, liquid hydrogen has been used in the aerospace industry, where large quantities of high-energy fuels are required to power rockets and spacecraft engines [12].

Ammonia (NH3)
Ammonia can be used as an energy carrier for green hydrogen onboard ships. The most common method of producing ammonia is through the Haber-Bosch process. In this process, hydrogen is combined with nitrogen under high pressure and temperature. Depending on the literature source, the efficiency of producing ammonia from green hydrogen variate. According to [23], the efficiency of producing ammonia from the electrolysis of water through the Haber-Bosch process is set to 52 %. [24] presents that the round-trip efficiency of the power-to-ammonia-to-power process is equal to 20.5%, while [25] provides that the efficiency of producing ammonia from hydrogen is 78 %.

Ammonia is typically stored on ships in specially designed, pressure-resistant tanks in its liquid form. To convert ammonia to liquid form, a temperature of -33 Celsius at atmospheric pressure is required. Liquid ammonia has a 70% higher hydrogen density than liquid hydrogen, which means it takes up less space on a ship [22]. This can make ammonia a favorable alternative for longer voyages.

In addition to using ammonia as a hydrogen carrier, there are predictions that the development of the first engine capable of directly utilizing ammonia will occur within the next three years [4]. The drawbacks of using ammonia as a fuel are the high investment costs, the energy losses connected to the chemical reactions, the nitrogen oxide (NOX) emission, and the fact that ammonia is a toxic and corrosive gas. In the event of a large-scale ammonia gas leak, there is a risk of severe consequences, including potential harm to human life [22]. The mentioned challenges highlight the need for comprehensive safety measures and technological advancements before the widespread adoption of ammonia as a maritime fuel can occur.

Methanol
Methanol (CH3OH) serves as an alternative hydrogen carrier that can be effectively stored and used onboard ships. It offers several advantages compared to compressed and liquid hydrogen, including a higher energy density and a relatively safer storage profile. Methanol, when combined with water, can provide up to six times the energy density of compressed hydrogen [26], and twice the energy density of liquid hydrogen [27]. This higher energy density allows for a reduced onboard volume requirement for storage. Onboard the ship, the methanol fuel is mixed with water and undergoes a process known as reforming, which converts the methanol into hydrogen and CO2. The hydrogen is then separated and utilized for electric propulsion of the ship. The remaining CO2 is captured and returned to the methanol tanks in liquid form. This captured CO2 can be transported to ports and used for the production of new methanol, ensuring a closed-loop system. Methanol can also be produced from different sources, including natural gas and biogas. The International Maritime Organization IMO has established guidelines for the use of methanol

as a marine fuel, which further supports its adoption and implementation as an alternative fuel option.

Fuel cells

The utilization of fuel cell technology plays a crucial role in enabling electric propulsion on ships, utilizing fuels such as hydrogen, ammonia, or methanol. A typical fuel cell consists of an anode, cathode, and electrolyte. The chemical reaction which happens depends on the type of fuel cell. The most common fuel cells of today are; proton exchange membrane fuel cell (PEMFC), molten carbonate fuel cell (MCFC) and solid oxide fuel cell (SOFC). For a PEMFC, the chemical reaction between hydrogen and oxygen with a membrane electrode assembly MEA creates electricity, water, and waste heat. The process operates in the opposite direction than an electrolyser.

The PEMFC offers several advantages, including high power density and the ability to quickly respond to changes in power demand, similar to a diesel engine. These fuel cells are compact in size, making them well-suited for small-scale distribution applications. In contrast, high-temperature fuel cells like MCFC and SOFC tend to be larger and have slower startup times. However, ships with enough space can utilize the waste heat generated by these fuel cells, making them beneficial options. In addition, the PEMFC only uses hydrogen as fuel, while the other two fuel cells can consume hydrogen, LNG, methanol, ammonia, and diesel. In particular, SOFC will be a very suitable choice for ammonia applications [28].

The three mentioned fuel cells have been tested in different vessels, but the technology is still considered immature.[28] addresses several challenges related to the development of ship propulsion through hydrogen fuel cells as the primary source of energy. One of the main barriers to implementing more fuel cells is the efficiency rate. Table 2.5 provides an overview of the efficiency levels reported by various sources for different types of fuel cells. A noticeable discrepancy can be observed between the efficiencies reported by [22],[28], [29]. This is probably because of the uncertainties around the technology, as well as different approaches and operating conditions employed in fuel cell implementation. For instance, the efficiency of SOFC can rise by 20 % if the waste heat is being reused onboard [28]. Higher efficiency in the fuel cell leads to an overall lower energy demand for green fuels.

Table 2.5: Efficiencies for different fuel cells according to three different sources; [28], [29], [22]

Fuel cells	Efficiency [%], [28]	Efficiency [%], [29]	Efficiency [%], [22]
PEMFC	50-60	45	35-70
SOFC	45-60	56	60-80
MCFC	45-60	-	65-70

2.1.3 Charge powered ships

This subsection is based on my work done in the specialization project in autumn 2022 [1]. However, some of the paragraphs have been modified to achieve a better formulation.

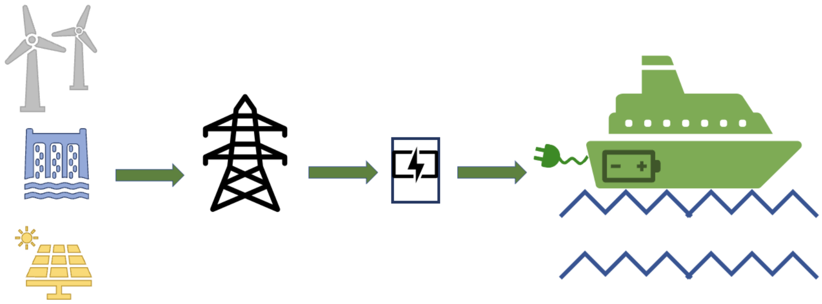


Figure 2.6: Simplified illustration of the power chain for electric vessels

"The direct use of electricity through batteries in ships is the most energy-efficient alternative considering fuels. The power is directly used from the electricity grid to charge the battery, which then is used in an electric engine to power the ship. If the electricity is produced from renewable sources, the CO2 emission of fully electric vessels is nearly zero [30]" [1] (pp.20-21).

"The battery capacity and technology have been developed and improved quickly in recent years. The policy and implementation of electric cars have been a driver for the development of battery technology. Today, the main battery types are; lead-acid batteries, nickel metal hydride (NiMH), lithium-ion batteries, NiCd batteries and Lithium-polymer batteries [31], where lithium-ion batteries are the most common battery type in vehicles and ferries. Primarily because of its high energy density, low price, and lightweight compared to the other battery types. The prices of batteries tend to decrease. Since 2016, the prices of lithium-ion battery cells dropped by 50 % [30]" [1] (pp.21).

Charge-powered ships are normally divided into three types; full-electric ships, plug-in hybrid ships and hybrid ships. In a full-electric ship, the batteries supply all the power for both propulsion and auxiliary systems. The plug-in hybrid ships use both a battery and a conventional engine for the ship's propulsion. Normally this type of ship uses the batteries alone during specific parts of the route, such as maneuvering in port and during stand-by operations. The last type, a hybrid ship, uses batteries to increase its engine performance and does not use shore power to charge its batteries [32].

"The barriers to using full-electric vessels are, first of all, the weight and capacity of the required battery. The battery technology still needs to be improved for vessels traveling long distances, with high speeds, or in heavy weather conditions. Other barriers to full electric vessels are the infrastructure of charging in ports, how the charging demand will affect the power grid and the investment costs of the technology. The local power networks connected to ports need to handle high-capacity peaks during charging. Depending on the vessel's size and required charging time, the capacity needs differ. For example, charging 1000 kWh (almost equivalent to 100 liters of oil fuel) in 30 minutes require a power of 2000 kW. If the vessel only has 10 minutes in port, the required power capacity would be 6000 kW to cover the demand [33]. The use of full-electric ships is most feasible for ferries and short-sea shipping with regular routes [9]" [1] (pp.21).

A plug-in hybrid solution, combining the battery with other fuels, can be an alternative for more vessel categories. With the hybrid solution, a reduction in greenhouse gas (GHG) emission is possible, but it will not be a carbon-free alternative unless the other fuel can be considered as a green fuel. A study provided by [34], suggests that a plug-in hybrid configuration integrating battery and hydrogen technologies can be implemented in larger vessels with higher energy demands, enabling them to operate primarily on green fuels [34]. This approach allows for greater operational flexibility and increased sustainability in maritime transportation. The plug-in hybrid solution is in further parts of this master thesis referred to as "Green Hybrid".

2.1.4 Shore power

Shore power refers to the electricity utilized by a ship during its stay at a port. It is primarily required for various hotel-related functions, such as lighting, cooling, heating, and other energy-dependent systems. Currently, most ships meet these energy demands through their onboard diesel-powered generators. However, to address environmental concerns such as greenhouse gas emissions, local pollution, and noise, the installation of shore power provides a more eco-friendly alternative [7].

The installation of shore power necessitates specific infrastructure both onshore and onboard ships. This infrastructure comprises several components, including a transformer station, frequency converter, cable management system, onboard connection panel, control system, and onboard transformer. Among these components, the frequency converter is the most expensive element in a charging and shore power system. The reason for requiring a frequency converter is that many ships operate on an onboard grid frequency of 60 Hz, while the grid frequency in Norway is 50 Hz [7].

2.2 The power grid and energy market

This section presents information about the power grid and energy market in Norway and the challenges it is facing regarding the electrification of the maritime sector. It also discusses the incentives for regulating power peaks and provides an explanation of electricity prices and grid tariffs. The information provided regarding grid tariffs and electricity prices serves as input parameters for the simulations conducted later in this master's thesis.

2.2.1 Power grid in Norway

Figure 2.7 depicts an overview of the power grid in Norway consisting of the transmission grid, regional grid, and distribution grid, each operating at specific voltage levels. Statnett is responsible for the transmission grid, and the security of the power supply in Norway. This entails continuous monitoring of the power grid to maintain the appropriate voltage and frequency (50 Hz), thereby guaranteeing an uninterrupted power provision for consumers.

Between each grid level, a transformer is connected to reduce the voltage level before the final delivery of power to electrical outlets at 230 V. The transmission grid distributes the power over long distances and requires a high voltage to minimize losses. The regional grid serves as an intermediary, connecting the transmission and distribution grid, typically operating at voltage levels ranging from 132 to 33 kV. Furthermore, the distribution grid supplies power to the end consumers and is divided into high-voltage and low-voltage distribution. Typically, large industries are connected to the high-voltage distribution grid, while electric cars and houses are connected to the low-voltage distribution grid [35].

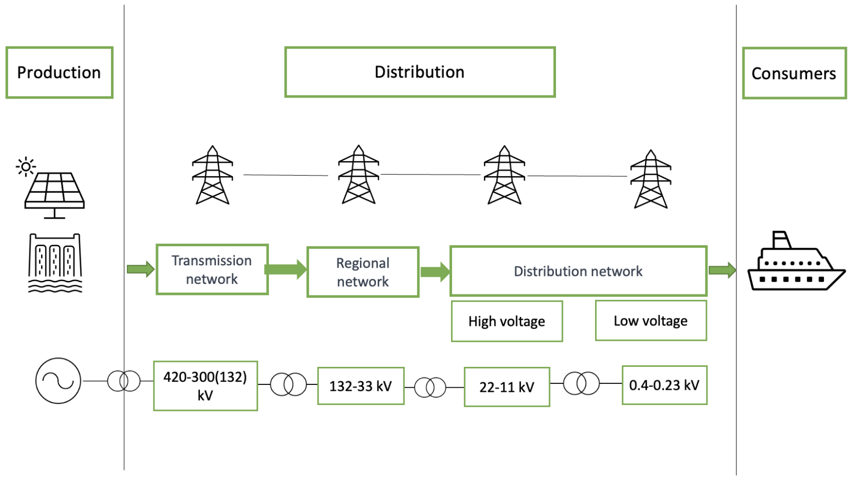


Figure 2.7: Overview of the transmission, regional and distribution grid with the corresponding voltage levels

2.2.2 Capacity problem in the power grid

One of the problems with the power grid today is the low capacities regarding the transmission lines, cables and transformations for the regional and transmission grids in several places in Norway [36]. Statnett is responsible for the transmission grid while the distribution companies are responsible for the regional and distribution grid. For these companies to ensure to cover the future capacity demand the grid components need to be designed accordingly.

When planning and designing the future grid capacity, the maximum power demand is a crucial factor. This means that the grid must be capable of distributing the power to everyone simultaneously during peak demand hours throughout the year. These peak demand periods typically occur during certain hours in the morning or evening on cold winter days when households require power for heating, cooking, and charging electric vehicles, while industries are also operating. For instance, the highest power peak in Norway during 2021 was between 9 and 10 Am, the 12 February, reaching a total power demand of 25 230 MW [37].

Future analysis of the expected capacity increase is normally based on the forecasted power demand for a chosen area. Normally, this analysis includes investigating the growth in population, housing construction, electrification of the transport sector, and well-known development of industry projects. However, this kind of analysis is challenging and the need for a better understanding and estimations within each sector is important.

Currently, there is a lack of power analysis regarding the electrification of the maritime sector. It is predicted that the power demand for a zero-emission port is high. However, there is an absence of detailed analysis regarding the appearance of this power peak. Meaning, if the highest power peak of the port coincide with the power peaks of the rest of the city the grid will not be able to handle it [10]. Elvia presents in their power system investigation article that the forecasts for using shore power are so uncertain that they cannot be used as a basis for measurements in the regional grid. Therefore, the analysis of the power demand for electrification in the maritime sector will provide valuable insight [10].

Oslo is an area that experiences high power demands, while in these hours the available capacities of the lines and transformers are low. Statnett has already planned to renew and reinforce the transmission lines from 300 kV to 420 kV in the area, and therefore gain a higher capacity [38]. Furthermore, ELVIA, which is responsible for both the regional and distribution grid in Oslo plans to upgrade all the regional grids from 50 kV to 132 kV [10]. Additionally, new lines and bigger cables will be implemented to increase the capacity in the area. However, the construction of new lines and cables are expensive and a detailed power analysis regarding future demand would provide valuable insight for this expansion.

2.2.3 Energy market

Understanding the total energy demand of a sector within a specific area yields crucial information relating to economic considerations and production planning. For instance, in 2021, Norway produced 157 TWh of electricity while consuming 140 TWh, resulting in a surplus of 17 TWh [39]. However, if the increase in energy demand rises faster than the production the country will have a deficit. The information about the predicted energy demand for different sectors can therefore provide valuable insight to the government and other stakeholders deciding to invest in more production processes such as wind and solar.

2.2.4 Peak shaving and Load Shifting

By introducing new green fuels such as green hydrogen, shore power, and charge power, the power demand at ports naturally will increase. For the power grid to be able to handle this new implementation some sort of power peak control should be implemented.

From the perspective of both the transmission system operators (TSO) and distribution system operators (DSO), peak loads pose two main challenges. Firstly, the grid infrastructure must be designed based on the highest load peak experienced in the system. Typically, these peaks occur only for a few hours each day, leading to unnecessary expenditure on grid capacity that remains underutilized for most of the time. Secondly, high loads can impact grid stability. If the power demand is higher than the supply capacity, it can result in instability. The power peaks can mainly be handled with two methods; peak shaving and load shifting. Peak shaving is a term defined as cutting the highest power peaks completely to reduce the peak. This method can either cut the peaks by actually reducing the consumption or implement a battery that provides power in the necessary hours. Load shifting, on the other hand, takes advantage of flexible demand by moving some of the demand to the hours of the day with lower demand and therefore reducing the peak [40].

From the consumer's perspective, handling their power peaks is beneficial economically. During hours with high power peaks, electricity prices are also high. Typically, electricity prices are higher during the day compared to nighttime. Shifting the main loads to off peaks hours can therefore be considered load shifting. Since the 1st of July 2022, consumers in Norway have paid grid tariffs based on the average of their three highest power peaks during the month. This measure is implemented to incentives individuals to reduce their hourly power peaks and can be considered a method of peak shaving [41],[42].

This master's thesis will implement both load shifting and peak shaving for the production of green hydrogen in port by considering the day-ahead price and the peak price per month. As long as the hydrogen storage has sufficient capacity to meet the demand, the electrolysis process can operate during the most cost-effective hours of the day. Furthermore, it is included a peak price for each month, which forces the model to minimize power peaks as much as possible and therefore includes peak shaving.

2.2.5 Grid Tariff and Electricity Price

The electricity bill is mainly divided into two parts; the electricity price and the grid tariff. The electricity price depends on the agreement between the consumer and the power supplier. The consumers are free to choose between different power suppliers, while the grid tariff depends on the prices from the DSO of the consumer's location. Normally, the consumer can choose between three agreements with the power supplier. The first agreement is a so-called "spot price agreement", which is based on the hourly prices of electricity (day-ahead prices). The day-ahead price varies throughout the day and depends on which of the five price areas of Norway the consumer is located.

Secondly, the ”fixed price agreement” assures a constant electricity price every month leading to full awareness of the price every month. However, this agreement is normally more expensive. The last agreement is a ”variable price agreement”, which provides a notice every 14 days of a change in the electricity price. This agreement follows the marked price but with a two weeks delay. All power suppliers have some additional costs to achieve economic benefit.

The grid tariff includes, among other things; the distribution of power to the customer, the development and maintenance of the electricity grid, the operation of the grid, the electricity meters and the public taxes. Historically, the grid tariff consisted of an energy price that depended on the total energy demand of the consumer. However, as described in subsection 2.2.4, the current grid tariff also includes a price depending on the consumer’s power peak [42]. For a company with an annual consumption above 100 000 (kWh), the grid tariff is divided into one fixed and three variable prices. The peak price depends on the month of the year [43].

1. The fixed price (NOK/month):
   The annual price covers the operation cost of the power grid.
2. Energy tariff (NOK/kWh):
   A small variable price for using the power grid is based on the energy consumption per hour.
3. Peak demand tariff (NOK/kWp/month):
   The variable price depends on the highest power peak of the month. The method of calculating this price changed the 1. July 2022.
4. The reactive power price:
   Installations that use the grid’s reactive power take up transmission capacity, increase grid losses, and alter grid voltage conditions. Elvia has the right to request that the client increase the power factor of the plant if reactive power withdrawal exceeds the predetermined threshold. Alternatively, the customer is responsible for paying the corresponding tariff for the surplus reactive power drawn. Reactive power tariff should encourage the construction of compensation facilities where necessary.
5. Public taxes
   The public taxes includes the required payment to the energy fund ENOVA, electricity tax and value-added tax (VAT).

Table 2.6 presents a simplification of the grid tariff provided by ELVIA, which will be implemented in further simulations in this master thesis. The fixed cost of 900 (NOK/month) includes the annual tax of 800 NOK to the energy found ENOVA. The production of green hydrogen is excepted for the electricity tax completely and will therefore, in further calculations not be included [22]. Furthermore, the reactive power price and value-added tax are excluded from further calculations due to simplification [43].

Table 2.6: Electricity cost based on numbers from ELVIA [43]

Grid tariff	**High Voltage connection (>100 000 kWh/year)**
Fixed cost	900 (NOK/month)
Peak demand tariff (Winter)	60 (NOK/kW/month)
Peak demand tariff (Summer)	25 (NOK/kW/month)
Energy tariff	0.03 (NOK/kWh)

2.2.6 Day-ahead price

The electricity price agreement between the consumer and power supplier, in this master thesis, includes the ”spot price agreement” without concerning any extra fee to the company. Therefore, the ”spot price agreement” considers only the day-ahead prices that represent the price of electricity produced each hour of the day and are provided by Nord Pool. The energy market has experienced unexpected price fluctuations over the last two years. Figure 2.8 displays the day-ahead prices from 2018 to 2022 for area NO1. The graph illustrates the extreme difference between the hourly prices in 2022 (green) and 2020 (yellow). Norway witnessed the lowest average day-ahead price ever in 2020, followed by a sharp increase in 2021 to the highest average day-ahead price on record. The increase continued in 2022 with an average price per hour as high as 1.94 NOK/kWh and the highest day-ahead price reaching 7.82 NOK/kWh [44]. Table 2.7 displays the highest spot price, the date it occurred, and the average hourly spot price for each year [44].

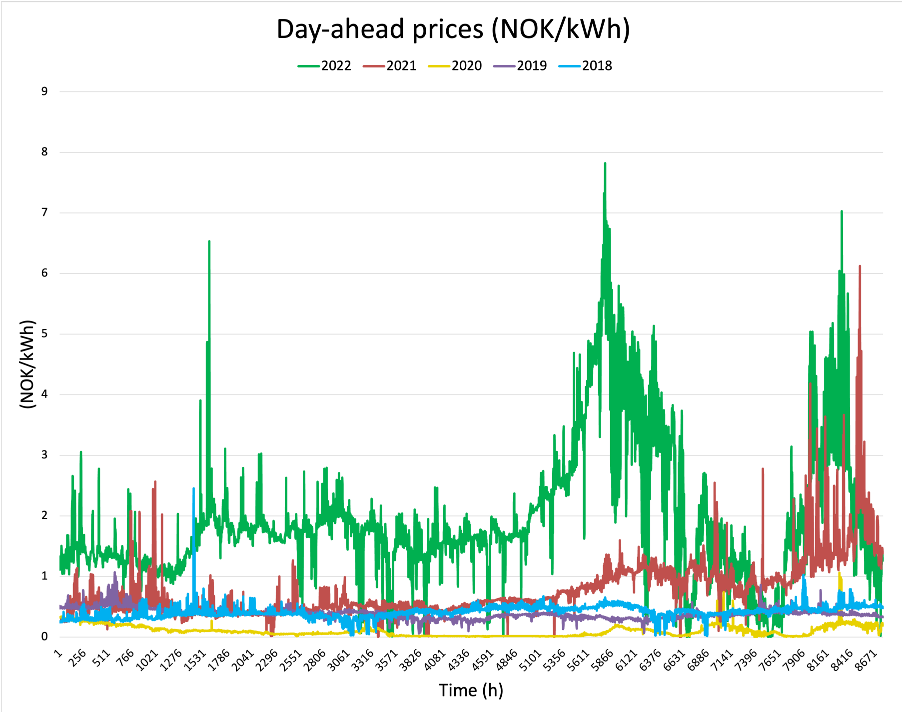


Figure 2.8: Day-ahead prices from 2018 to 2022 [44]

Table 2.7: The highest spot price, the date it occurred, and the average hourly spot price for each year from 2018 to 2022 [44]

NO1	2018	2019	2020	2021	2022
Max price (NOK/kWh)	2.45	1.07	1.06	6.12	7.82
Date with max price	1. March	24. January	10. December	21. December	30. August
Average price per hour (NOK/kWh)	0.42	0.39	0.10	0.76	1.94

There are many reasons for the extreme price rise, and the main reasons are listed and discussed below.

1. **The weather conditions in Norway**
   Norway gets 98 % of its power from hydropower plants [13]. Therefore, electricity prices vary both yearly and in the season depending on the rain and snowfall. In 2021, the south and east parts of Norway experienced the driest year in the last 20 years, resulting in a lower possibility for hydropower production [45].

2. **The different price areas in Norway**
   Norway is divided into five price areas. North of Norway, price areas NO3 and NO4 have good power connections to Sweden and its wind farms. However, the transmission lines from

north to south of Norway are constrained and cannot transport all the necessary capacity required in the south of Norway. Therefore, the high prices in Europe affect the prices in the south of Norway much more than in the north of Norway [46].

3. **The invasion of Ukraine in February 2022**
The European Union (EU) has implemented economic sanctions on Russia, including a ban on importing gas from the country. As Russia is a significant gas exporter to Europe, this sanction has impacted the energy market and energy supply in the region [47]. Electricity prices typically track gas prices due to the merit order. As a result, when gas prices rise, electricity prices also experience an increase.

4. **The power cable to Europe**
Norway has constructed two new underwater cable connections, Nordlink to Germany and North Sea Link to Great Britain, with the purpose of security of supply and facilitating the reduction of fossil energy use. The main goal of Europe is that all energy demand is covered by renewable sources. To achieve this goal, the power market relies on transmission lines, which enable energy to be transported from countries with a surplus production from renewable sources such as solar, wind or hydropower to those in need. Hydropower, which can be regulated, is a vital resource in achieving this goal. Nordlink and North Sea Link will provide Norway with cheaper energy during the winter season when the demand is higher than the country's supply [48]. However, according to a new analysis, the opening of these new cables increased the electricity price by 25 % [49].

5. **Other power plants in Europe**
Due to maintenance, France has shut down several of its nuclear power plants, resulting in a 50% decrease in productivity compared to the previous years [50]. Additionally, Europe experienced a dry time during the summer seasons of 2021 and 2022, which impacted both hydropower plants and the supply of coal to coal production which are normally transported via rivers [51].

To conclude, the energy market has experienced unexpected price fluctuations over the last two years. It is unclear whether these prices will continue to rise or if they will return to more typical conditions. The result from simulation based on the day-ahead prices from the last years can therefore be unsure. However, it will give an impression of how it can be if the prices now continue to be high.

2.3 Duration curve

A load duration curve shows the power demand of a power system during a given period. The curve illustrates how long the system ran at a specific load level and is organized in descending order according to the amount of demand. As a result, it makes it possible to determine how many hours throughout the simulated time the highest power peak occurs. This information can be useful in determining the capacity needed to size the system appropriately.

The utilization time is a measure of the total load demand compared to the maximum requirement, as shown in equation 2.2. The utilization time value represents the number of hours the system needs to produce at max capacity to cover the total demand for the entire duration [52].

$$U_t = \frac{E_{tot}}{P_{max}} \tag{2.2}$$

where;
U_t: Utilization time [h]
E_{tot}: Total energy demand [kWh]
P_{max}: highest power demand in one hour [kW]

Furthermore, the load factor can be expressed as the per-unit equivalent of the utilization time. It is calculated as the ratio of the utilization time to the total hours, as depicted in Equation 2.3. This factor indicates the proportion of the period in which the maximum load demand occurred.

$$L_f = \frac{U_t}{T} \tag{2.3}$$

where;
L_f: Load factor [p.u]
T: Total hours of duration [h]

A high utilization time and load factor are indicative of the system utilizing the maximum capacity for a significant number of hours within a year. This is advantageous since the investment costs associated with the electrolyzer capacity, hydrogen storage size, and transformer capacity are substantial. Therefore, it is financially beneficial to utilize the capacity paid for.

2.4 PV system

The further simulations included in this master thesis consider the production of electricity from local photovoltaic (PV) modules at the port. Therefore the calculation of power produced from solar power has been investigated. One PV module is approximately 1.6 m^2 and the power production per module per hour is calculated by (2.4) - (2.6) [53].

$$P_t = \frac{FF \cdot I_{sc} \cdot V_{oc} \cdot T_0}{E_0 \cdot \log(10^6 \cdot E_0)} \cdot \frac{E_t \cdot \log(10^6 \cdot E_t)}{T_{cell,t}} \cdot \eta_{inv} \tag{2.4}$$

where

$$FF = \frac{P_{mpp}}{V_{oc} \cdot I_{sc}} \tag{2.5}$$

The cell temperature is calculated from the following equation:

$$T_{cell,t} = T_t + \frac{NOCT - 20}{800} \cdot E_t + 275.15 \tag{2.6}$$

P_{mpp} : maximum power point of the module (W)
FF : fill factor of the module
V_{oc} : open circuit voltage (V)
I_{sc} : short circuit current (A)
$T_{cell,t}$: cell temperature (K)
T_t : measured temperature (°C)
T_0 : standard module temperature (K)
E_0 : standard irradiance (W/m^2)
E_t : measured irradiance (W/m^2)
η_{inv} : inverter efficiency
$NOCT$: nominal operating cell temperature

The measured temperature (T_t) and irradiates (E_t) are collected from 15 different measurement stations allocated all over Norway. Each of Norway´s five price zones has three measurement stations. Based on the measurement's spot, the solar production in each price area in 2015 was found. For instance, the measurement for NO1 are collected from Alvdal, Rakkestad and Roverud [53]. The rest of the parameters used in calculations are shown in the appendix A.

Figure 2.9 illustrate the solar production for 100 PV modules in the five different price areas of Norway. It can be observed that all the production curves follow a natural pattern, with the highest production during the summertime and less during winter. Table 2.8 displays the maximum power peak and total energy produced by the 100 PV modules in the different areas. Areas NO1 and NO2 have the most solar production, with a peak of around 20 kW and a yearly production of 25.5 MWh. The other areas are not far behind with a total energy production of 21.2 MWh, 22.0 MWh and 20.8 MWh for NO3, NO4 and NO5, respectively. Furthermore, NO4 produces close to zero at the beginning and end of the year. Matching the fact that it is dark during this time of year in North of Norway.

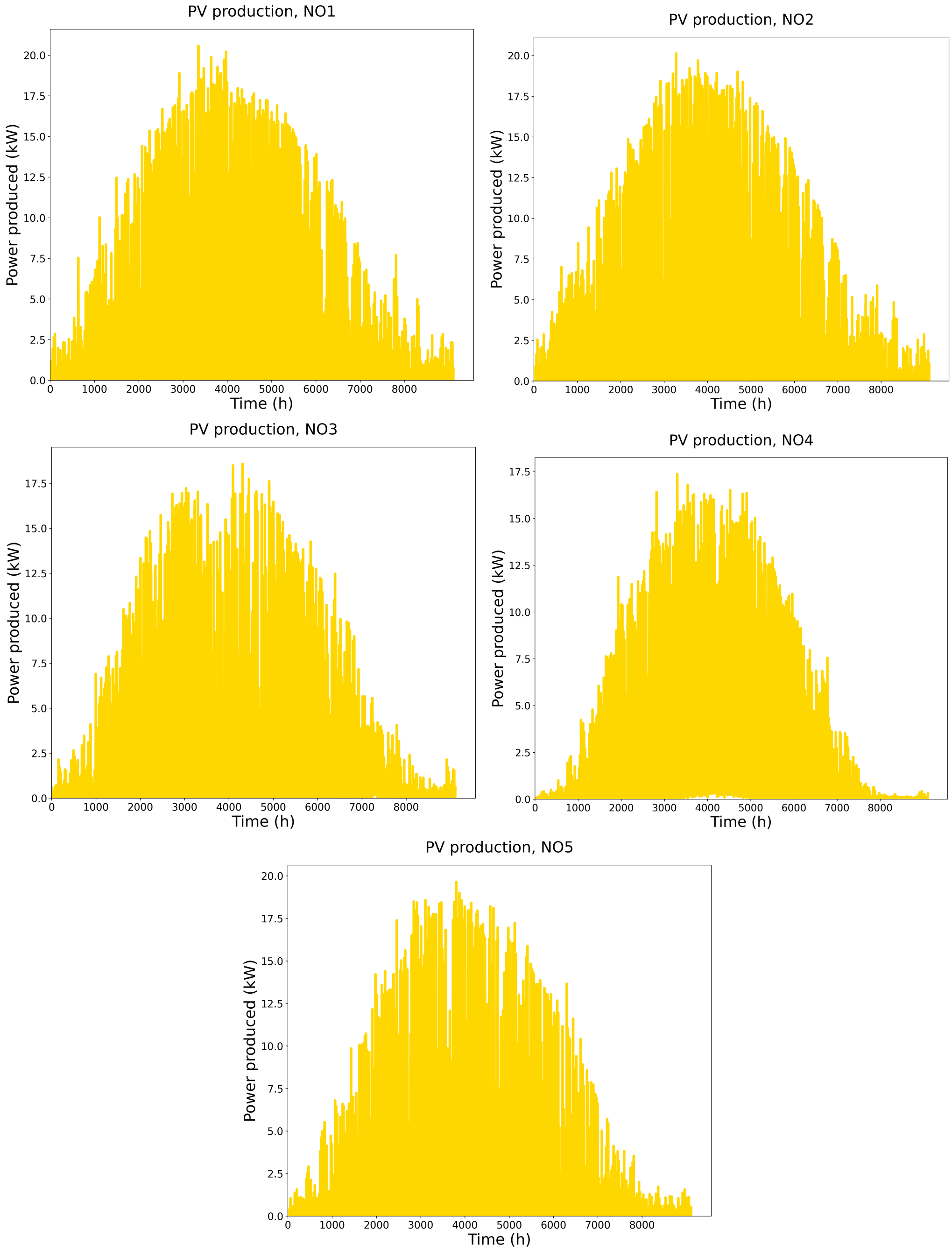


Figure 2.9: PV production per hour during 2015 for the five price areas, NO1, NO2, NO3, NO4 and NO5

Table 2.8: Total energy and maximum power peak of the PV production in the five price areas of Norway in 2015

	NO1	NO2	NO3	NO4	NO5
Maximum power peak(kW)	21	20	19	17	20
Total energy produced (MWh)	25.54	25.50	21.26	22.04	20.83

Figure 2.10 shows the production of the PV panels on the 1st of January for NO1 and NO2, respectively. In the left plot, representing NO1, the solar panels produced power in all hours of the 24 hours simulated, while the solar panels for NO2 only produces between hours 8 to 15. This finding was unexpected, given that during January, it is numerous hours of darkness. Nevertheless, the amount of sunlight detected during these hours in NO1 is considered so small that the resultant impact on the outcomes is deemed to be inconsequential in further simulations in this master thesis.

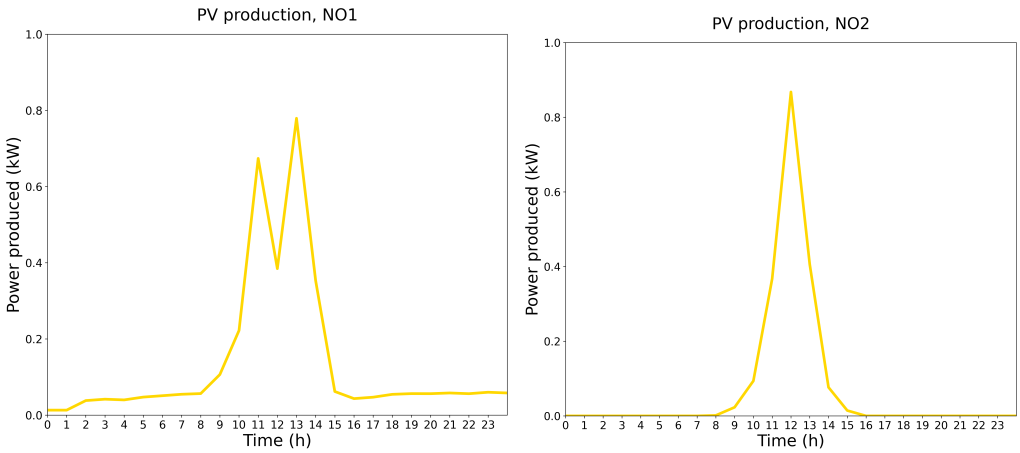


Figure 2.10: PV production for 1. of January 2015 in price area NO1 (left) and NO2 (right)

2.5 Investment costs for electrolyser, hydrogen storage and transformer

This master's thesis incorporates investment costs for electrolyser, hydrogen storage, and a transformer into the optimization problem to determine the optimal capacities required to meet the demand while minimizing the overall cost in port. Thus, this section presents the researched prices for the mentioned parameters. Generally, prices vary based on size, brand, and capacity. Moreover, as the technologies are still under development, it is expected that prices will decrease over time.

2.5.1 Investment costs for electrolysis

The investment costs of electrolysis vary depending on the chosen type (PEM, Alkaline, SOEC), sizes, and capacities. From the investigated sources it is chosen to present numbers from three scientific studies.

Firstly, the report [54] presents an overview of some investment prices for electrolysis with a variation of capacity between 305 kW to 230 MW. The investment costs per kilowatt decrease corresponding to the increase in capacity, and are therefore found in a cost range between 668 €/kW to 2070 €/kW as presented in 2.9:

Table 2.9: Investment cost of electrolysis based on capacity

	Capacity	Investment cost (€/kW)	Source
Small unit	305 kW	2070	[55], 2005
Small unit	300-1000 kW	1100-1300	[56], 2007
Small/Medium plant	2300 kW	1500	[55], 2005
Medium plant	25 MW	974	[55], 2005
Large plant	230 MW	668	[55], 2005

Secondly, [57] provides an analysis of electrolysis investment costs spanning the period from 1990 to 2017. Additionally, the study investigates and presents estimated costs until the year 2030. Figure 2.11 illustrates the development of cost projections and estimations for alkaline and PEM electrolyzers during the time period [57]. According to the article, the cost range for alkaline electrolysis in 1995 was approximately 800 to 2400 €/kW. However, it is projected to narrow down to a range of 787 to 906 €/kW by the year 2030. On the other hand, the cost range for PEM electrolysers in 1995 was wider, ranging from 306 to 4748 €/kW. The estimated price range for PEM electrolyzers in 2030 is projected to be between 397 and 955 €/kW [57].

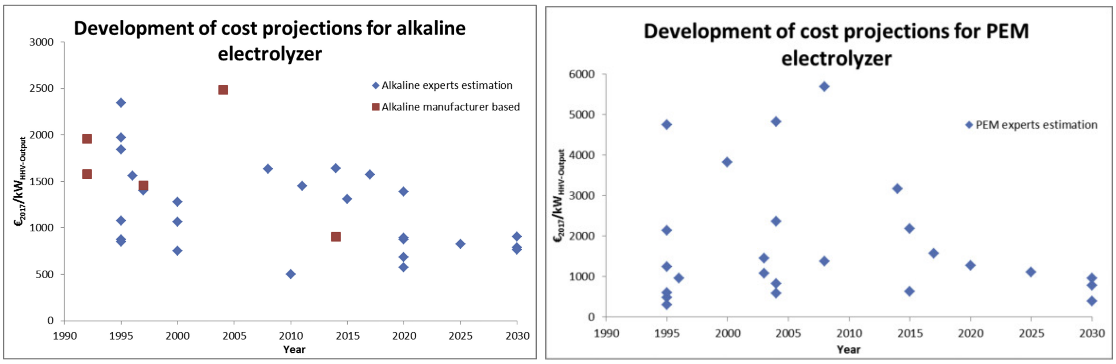


Figure 2.11: Development of cost projections for alkaline (left) and PEM (right) electrolysis [57]

[58] presents a comprehensive report that provides a system analysis of the techno-economic, legal, and regulatory aspects of utilizing hydrogen for various applications. The report was developed by a global team consisting of 60 members from 39 organizations across 17 countries. Figure 2.12 illustrates the dividing of the three different electrolysis types (AEL, PEM, and SOEC) across three time periods: 2012-2020, 2021-2030, and 2031-2050. The electrolysis type in each time period is based on results from 109 eligible scenarios. The predicted dividing in 2030 will be in the order alkaline (approximately 40 %), PEM (approximately 30 %) and the SOEC (approximately 25 %). Additionally, figure 2.13 presents the estimated average electrolysis investment costs for the aforementioned electrolysis types during the specified time periods [58].

According to the study, the average investment cost in the time period between 2031 and 2050 for an alkaline electrolyser is predicted to be approximately 640 €/kW, while for a PEM electrolyser, the average investment cost is projected to be around 440 €/kW. These estimates reflect the evolving trends in electrolysis technology and the anticipated reduction in investment costs over time.

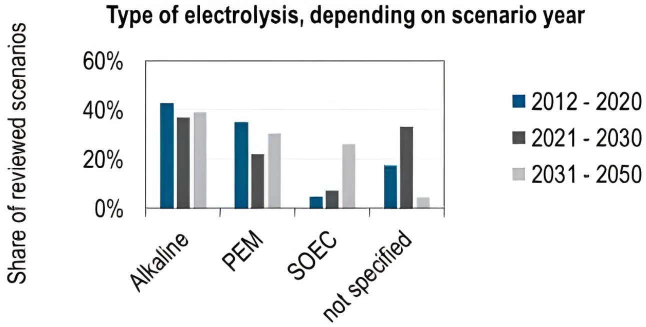


Figure 2.12: Type of electrolysis depending on each time period based on 109 eligible scenarios [58].

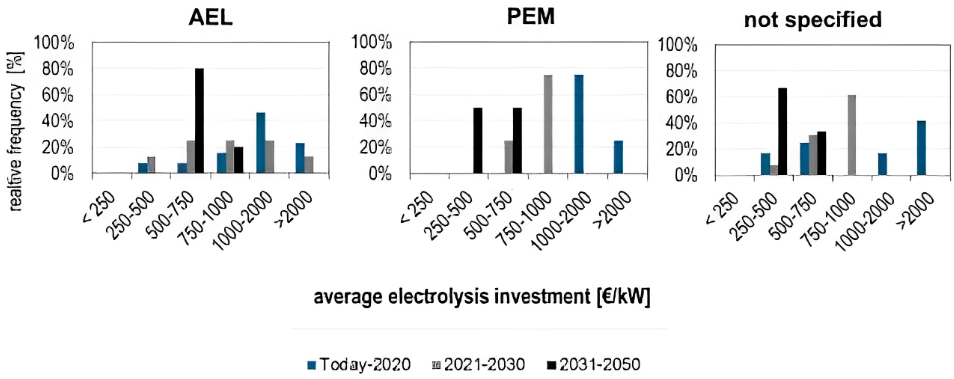


Figure 2.13: Average investment cost €/kW for the different types of electrolysis in the three time periods (2020), (2021-2030) and (2031-2050)[58].

All the studies present different estimations of the investment cost of electrolysis. For a PEM electrolysis in 2030, the investment costs presented are in a range between 250 to 955 €/kW, while the cost range for the alkaline is between 500 to 906 €/kW.

2.5.2 Hydrogen storage price

The investment cost of hydrogen storage can vary significantly based on variables such as the type, the material, the size and the capacity. This master thesis focuses on the analysis of literature considering investment costs associated with compressed hydrogen storage on land, which is a widely employed and commercially viable method. The results of the cost analysis are summarized in Table 2.10, providing a comparative overview of the investment costs and the corresponding characteristics reported in the literature. The ideal gas law, presented in the appendix B, is used to calculate from the different units of measurement into €/kg which is presented in table 2.10.

Table 2.10: Investment costs for hydrogen storage with different characteristics, based on different sources. L is in this case lifetime, P is pressure and V is volume

Characteristics	Investment cost	Source
P: 30 bar L: 20 years	245 €/kg	[58], 2020
P: 30 bar L: 20 years	175 €/kg	[58], 2020
P:(low) L: 25 years	606 €/kg	[59],2015
P: not given L: 25 years	565- 1042 €/kg	[60],2020
P : 100 bar L: 30 years V: 300 m^3	500 €/kg	[61], 2022
P: 15-250 bar L: 20 years	500 €/kg	[62], 2017
P: not given L: 25 years	482 €/kg	[63], 2016
P: not given L: not given V: small storage	606 €/kg	[64],2001
P: not given L: not given V: big storage	1819 €/kg	[64],2001
P: 440 bar L: 20 years V: 900-5000 m^3	545 €/kg	[65],2010
P: 200 bar, V: 2000-10000 m^3 L: 20 years	356-467 €/kg	[66], 2004
P: 150 bar L: not given	1240 €/kg	[55], 2005
P: 500 bar L: not given	450 €/kg	[55], 2005
P: not given L: not given	273-1001 €/kg	[67], 2006
P: 430 bar L: not given	428 - 744 €/kg	[68], 2006

The table displays the investment costs for compressed hydrogen, with prices ranging from 175 €/kg to 1829 €/kg. Nevertheless, the majority of sources report investment costs within the range of 400-600 €/kg. The investigated sources present hydrogen storage with pressure ranging from 30 bar to 500 bar, with a lifetime between 20 to 30 years.

2.5.3 Investment costs of transformer

The investment cost of a transformer depends on various factors, such as the size, capacity, manufacturer and the location where it will be installed. According to [69], formula 2.7 estimates the investment cost of transformers with a capacity between 1.4 MW to 10 MW.

$$C_{trans} = 0.0624 \cdot P^{1.1266} \tag{2.7}$$

where C_{trans} is the estimated cost given in thousand NOK, and P is the transmission capacity in kilowatt. In this case, a 10 MW transformer costs approximately 2 000 000 NOK.

For transformers with a capacity below 1400 kW, the following regression formula can be utilized [69]:

$$C_{trans} = 0.123P + 48.28 \tag{2.8}$$

There have also been found other prices corresponding to transformers with larger capacities. The findings are presented in 2.11 [70]. It can be observed that the investment cost for a 63 (MVA) transformer is lower than the price calculated considering 10 MW transformer in the formula of [69]. Furthermore, there is a higher increase in the investment cost from 63 MVA to 200 MVA than from 200 to 400 MVA.

Table 2.11: The investment cost for transformers of different capacities [70]

Transformer [MVA]	**Investment [€]**
63	1 782 608
100	2 253 521
200	3 368 532
400	4 376 786

2.6 Uncertainties in the prediction of power, energy and hydrogen demand in a zero-emission port

The optimization of the power, energy, and hydrogen demand for a zero-emission port poses a few difficulties regarding uncertain predictions for the future. In this master thesis the main insecurities are the investment costs for hydrogen components, the dynamics of the electricity market, the business and usage patterns of the port, and the evolving landscape of the hydrogen market. The dissolving of these uncertainties to predict the future towards a zero-emission port exactly is overstepping the focus of this work and therefore these points are explained in more detail.

Uncertainties in the prediction for investment costs of hydrogen components
The investment costs are typically spread over multiple years due to the gradual nature of industry changes. Consequently, components are broken down into multiple smaller systems and purchased in different years to align with the evolving maritime landscape. As the hydrogen market experiences significant transformations and becomes a commercial player in the energy sector, the efficiency of electrolysis and fuel cells is expected to increase while investment costs are projected to decrease. Nevertheless, these dynamic shifts necessitate expert knowledge and deeper insight into the hydrogen market to effectively anticipate and evaluate these uncertainties. Uncertainties in the prediction of the electricity market. The electricity prices in Norway exhibit a high level of volatility in the last years, as discussed in section 2.2.6, primarily due to the ongoing transition towards a greener energy market in Europe and the geopolitical uncertainties prevailing globally, such as the war in Ukraine. As a result, predicting the future movement of electricity prices is challenging, often requiring the expertise of an entire team dedicated to developing multiple scenarios with associated probabilities. Furthermore, the planning of the power grid to adequately meet future demand is necessitating more information and deeper insights into the responsibilities. Considering the multitude of uncertainties surrounding the electricity price, grid planning, and market dynamics in the upcoming time, accurate predictions become a challenging task.

Uncertainties in the prediction of the port business and usage
The future planning of a port involves significant uncertainties that necessitate in-depth knowledge of port planning, business analysis, and comprehensive insights into the financial aspects of the port. Firstly, one major aspect is the uncertainty surrounding the business planning about the port's intention to establish a profitable venture by selling hydrogen and electricity to ships, determining the pricing strategy that strikes a balance between profitability and competitiveness. Furthermore,

there are insecurities regarding potential government regulations of hydrogen bunkering into ships and associated taxes. These aspects require a detailed and extensive business analysis. Secondly, the port's logistical considerations involve projections for the number and types of ships expected in the future and the possibility of optimizing quay operations to ensure a balanced power demand throughout the day. These aspects require detailed information of the port's anticipated usage by ships. Overall, addressing these uncertainties within a port requires expertise in various fields, including port planning, business analysis, and acquiring deeper insights and specific information, representing a comprehensive undertaking.

Uncertainties in the prediction of the hydrogen market
The role of hydrogen in the energy market remains uncertain, despite of predictions suggesting a promising future as an energy carrier, storage medium, and energy source. Nevertheless, the dimension of the hydrogen market and which key stakeholders will take a leading role in this field remains unknown. There are a lot of unresolved concerns regarding the potential establishment of a hydrogen grid, if industries can connect to it, and the configuration and operation of such a system, comparatively to the existing electric infrastructure. These numerous uncertainties surrounding the occurrence, timing, how the hydrogen will impact the energy market, and whether the maritime sector can effectively profit by it.

Chapter 3

Alternative Fuels of the Future

To be able to calculate the future energy, power, and hydrogen demand for the maritime sector it is important to investigate the actual possibilities of implementation of the green fuels. This chapter presents an overview and status of ships and projects that use or are predicted to use batteries and green hydrogen by 2050.

This chapter is directly excerpted from my specialization project of autumn 2022 [1] (pp.23-34). I have reused the formulations in [1] because it was not necessary to modify them for the purpose of this master thesis.

3.1 Current situation

Most ships today use fossil fuels. Three standard fuels of today are heavy fuel oil (HFO), marine gas oil (MGO)/ marine diesel oil (MDO) and low sulfur fuel oil (LSFO). Figure 3.1 presents statistics of the fuels used in operation and on order for the next 4 years. Of all the ships in operation in the world, 99.47 % of them are driven by conventional fuel. The last 0.53 % are using the alternative fuels LNG, LPG, methanol, or hydrogen. Out of all the ships in order for the next four years, 85.8 % are with conventional fuels. Out of the alternative fueled ship ordered constitutes hydrogen and methanol together 2 % [71].

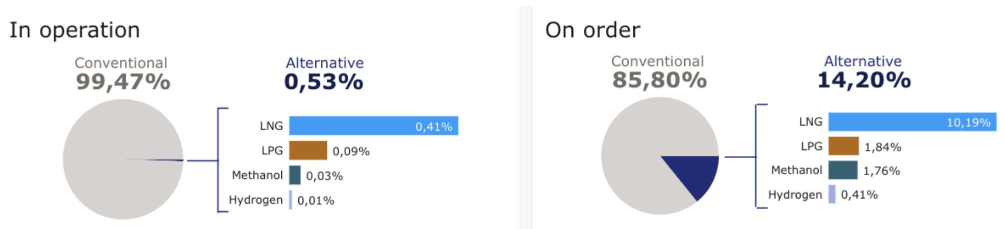


Figure 3.1: Alternative fuel uptake in the world fleet by number of ships [71]

According to the continuously updated statistics provided by [71], there are currently 769 battery-powered ships in operation worldwide, with 294 of them being operational in Norway, as presented in figure 3.2 [71]. Moreover, there are 237 new ships planned for the next four years, out of which 48 are intended for Norway. A significant increase in the adoption of electric vessels can be observed since the introduction of the first electric ferry, "Ampere," in 2014 [72]. This trend highlights the effectiveness of Norwegian government policies and initiatives in driving the transformation of the maritime sector. The battery-powered ships of Norway are divided mainly into the following ship types; 103 car/passenger ferries, 12 cruise ships, 51 fishing vessels, and 48 offshore supply vessels. However, it is noteworthy that only 5% of these battery-powered ships are fully electric, while most utilize hybrid solutions [71].

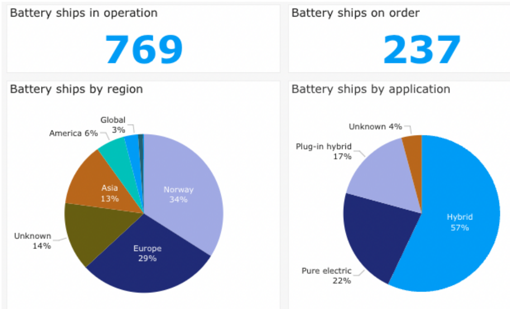


Figure 3.2: Statistic of battery ships in the maritime sector [71]

The utilization of hydrogen fuel cells in ships has been a subject of development since 2000 [28]. However, due to various barriers such as storage limitations, safety concerns, economic factors, and infrastructure, alternative technologies have been prioritized over hydrogen fuel cells in the maritime industry. As a result, there are currently only six pure hydrogen-powered ships (liquid or compressed hydrogen) registered and operational worldwide. However, there are 19 pure hydrogen-powered ships planned for construction and operation before 2028. These upcoming hydrogen-powered ships primarily fall into the categories of cruise ships and other specialized activities [71].

Furthermore, as presented in 2.1.2, methanol and ammonia are considered potential hydrogen carriers. Additionally, both fuels can either be directly used in engines or converted back to hydrogen. There are presently 26 ships utilizing methanol as their fuel source. Among these ships, the majority are oil and chemical tankers. There are 76 new container ships on order, scheduled to be equipped with methanol as fuel, with an anticipated readiness by 2028. Ammonia as a fuel option for ships is undergoing active development and exploration. Currently, there are no operational ships that utilize ammonia as their primary fuel source or plans for ammonia-powered ships within the next four years. However, the infrastructure of ammonia bunkering is predicted to be available in the next few years [9].

3.1.1 Overview of different battery and hydrogen vessels

Table 3.1 and 3.2, present an overview of different battery and hydrogen ships that either are in operation or will be in operation in the close future. The tables 3.1 and 3.2 present that it is technologically possible for ferries, fishing vessels, offshore vessels, and fast ferries to be fully electric, while the projects for hydrogen ships include ferries, cargo ships, and coastal ferries.

Table 3.1: Overview and information about electric vessels in operation

Battery vessels:				
Year of operation	**Name of vessel and company**	**Information**	**Location**	**Source**
2014	”MF Ampere ” - Norled	First fully electric car ferry in the world. - Size: 80m $\cdot 21m$ - Capacity: 120 cars and 360 passengers - Battery capacity: 1094 kWh	Sognefjorden, E39, Lavik- Oppedal	[72]
2015	”Karoline” / ” Selfa Arctic El-Max 1099”	First fishing vessel in Norway with an electric engine. - Size: 11m · 4m - Battery capacity: 195 kWh The vessel also has a diesel engine for backup reasons. The vessel is now in disposition for Sintef to test hydrogen/fuel cells and energy captures on board.	Tromsø	[73], [74]
2018	”ELfrida” - Salmar farming	First electric fish farm vessel in the world. - Size: 13m · 8m. - Battery capacity: 160 kWh	Kattholmen	[75]
2018	”Future of the Fjords” - Brødrene AA	All electric passenger catamaran (tourist vessel) - Size: 42m · 15m - Battery capacity: 2 x 900 kWh	Flåm-Gudvangen	[76]
2022	”Medstraum”	First full electric high-speed ferry. - Capacity:147 passengers	Stavanger, Hommersåk - Byøyene.	[77], [78]

Table 3.2: Status and information of different hydrogen fuel ships under development

Hydrogen vessels				
Predicted year of operation	**Name of vessel and company**	**Information**	**Location**	**Source**
31.03.2023	”MF Hydra” - Norled	The first hydrogen hybrid ship driven by liquid hydrogen as fuel. -Winner of Skipsrevyens award ”Ship of the year”. -Today in operation with batteries and fuel cell. -Size: 82.4 meters long -Capacity: 300 passengers and 80 cars. -Fuel cell: 2 x 200 kWh -Battery: 1360 kWh	Hjemeland-Skipavik-Nesvik	[79], [80]
2024	”Topeka” - Wilhelmsen	World first Ro-Ro ships with hydrogen fuel cells. The two ships will carry goods between oil platforms on the west coast.	Oil platforms; Tanager, Dusavik Ågotnes and Mongstad	[81]
2025	-Statens vegvesen	Two hydrogen ferries in Lofoten. - Minimum use of hydrogen : 85 % - Size: 120 cars, 399 passengers, 12 trailers	Bodø- Røst-Værøy- Moskenes	[82]
Unsure	”FreeCO2ast Project” - HAV Group	Project that develop the use of hydrogen for the coastal ferries. Is a part of the Pilot-E project.	Norway	[83], [84]
Unsure	”Aero 42 Hydrogen” - Brødrene Aa	Two fast ferries with hydrogen fuel cells. Size: 42.8 meters long Capacity: 275 passenger Speed: 34 knots	Trondheim-Kristiansund	[85], [86]

3.1.2 ENOVA projects 2022

In addition to the hydrogen projects shown in table 3.2, [87] published an overview of projects that received support for developing green hydrogen production for the maritime sector and hydrogen or ammonia-powered vessels by ENOVA. ENOVA is a state-owned enterprise, which works for Norway's transition to a low-emission society by supporting climate-neutral incentives. The total support of 1.12 billion NOK was divided between establishing five green hydrogen production plants along Norway's coast and seven pioneering hydrogen and ammonia-powered vessels [87]. The seven ships that receive support are:

Færder Tankers Norway AS: This will be the world's first ammonia-powered tankers and carriers. The plan is to build two tankers and two car carriers that use ammonia as fuel. The project received 205.6 million NOK [87].

Ocean Infinity: Will consist of two container ships that use hydrogen as fuel. If the company succeeds, the ships will be the first hydrogen-powered container ships in the world. The ships will travel between Rotterdam and the port of Oslo. The project received 148.6 million NOK [87].

Thor Dahl bulk: Plan to build a hydrogen-powered bulk carrier that will use compressed hydrogen when using fuel cells. The project received 97 million NOK [87].

For the practical use of hydrogen and ammonia vessels, the refill infrastructure needs to be established. In 2021, ENOVA received 29 applications for support of establishing green hydrogen production for the maritime sector [88]. Out of these 29 applications, 15 locations were considered qualified to compete for support, as shown in appendix C. In the end, five locations Glomfjord, Rørvik, Hitra, Florø, and Kristiansand received the support of NOK 669 million. According to the CEO of Enova, Nils Kristian Nakstad, these plants will produce and deliver green hydrogen to between 35 and 40 vessels [87].

Renergy is one of the companies that work with the development of the renewable hydrogen production plant in Rørvik [89]. In addition, together with other companies, Renergy is a part of the Pilot-E project called "UBÅT" [90]. This project aims to develop and realize a hydrogen-electric work boat for the aquaculture industry, as well as a complete solution for a flexible supply of green hydrogen as fuel [89]. The production plant is predicted to be utilized from 2025 [90] [91].

3.2 Literature review of future fuels in the different vessel categories

This section provides an overview of the projected adoption of green fuels across various ship types, based on information gathered from multiple sources within the maritime industry. The results mainly focus on pure hydrogen, ammonia and methanol.

Prediction of the future fuels presented by HyInfra

[14] outlines the potential application of zero-carbon fuels for various types of ships. The findings are presented in table 3.3. The listed vessel types are mostly ammonia and compressed hydrogen considered the primary fuel, while liquid hydrogen is suggested as the secondary fuel. It is important to note that ships within the same category may vary significantly in terms of size and operational characteristics, leading to the recommendation of both a primary and secondary zero-carbon energy carrier. In addition to the presented table, [14] presents that the coastal route connecting Bergen and Kirkenes has the potential to utilize liquid hydrogen and a significant portion of offshore vessels can utilize ammonia as zero-emission fuel.

Table 3.3: Potential application of zero-carbon fuels for various types of ships [14]

Vessel type	Primary zero carbon energy carrier	Secondary zero carbon energy carrier
Cruise vessels	Ammonia	Liquid hydrogen
High speed light crafts	Compressed hydrogen	Liquid hydrogen
Harbour operating vessels	Battery	Compressed hydrogen
Fish farming vessels	Ammonia	Compressed hydrogen
Coastal fishing vessels	Compressed hydrogen	Battery hybrid
Seagoing fishing vessels	Ammonia	Liquid hydrogen
Domestic car ferries	Compressed hydrogen	Liquid hydrogen / ammonia
International car ferries	Ammonia	Liquid hydrogen
General cargo vessels	Ammonia	Liquid hydrogen
PSV and AHTS	Ammonia	Liquid hydrogen
Mobile drilling units (MODU)	Ammonia	None

Prediction of the future fuels presented by DNV

DNV presents three reports considering the possibilities of alternative fuels for the different ship types. The first report, [22], presents an estimation of the vessel types that theoretically and realistically can utilize pure hydrogen in Norway by 2030. The estimation is based on the assumption that only the following five ports could produce green hydrogen for the maritime sector in 2030; Bergen, Ålesund, Tromsø, Kristiansund, and Stavanger. Further, the ships that spend more than 80 % of the time in the Norwegian economic zone (NØS) and at least half of the annual calls in the five ports identified are considered. Based on these assumptions is a theoretical potential of 186 hydrogen ships in 2030 presented. However, with a realistic perspective, [22], predicted that only 18 ships would be driven by hydrogen in 2030. Table 3.4 shows the theoretic and realistic potential of hydrogen ships divided by ship type in 2030.

Table 3.4: Number of ships in theoretical and realistic potential with the use of hydrogen as fuel in 2030, according to [22]

Ship segment	Theoretical potential	Realistic potential
Car ferry	9	9
Offshore	8	4
The coastal route	13	not quantified
Cruise	48	not quantified
Service/others	22	not quantified
Speedboats / fast ferries	40	5
Fishing vessels	48	limited testing
Wet/dry bulk and cargo ships	7	limited testing
Total	186	-

The second report,[9], presents a prediction for the green fuel mix in 2050, which mainly will consist of bio-MGO, bio-LNG, e-MGO, e-ammonia, blue ammonia, and bio-methanol. Where the e-MGO and e-ammonia are produced from hydrogen. This is based on a realistic mix considering policy, economy, and infrastructure.

Lastly, [15] presents an overview of which technology is possible to use and implement for the different ship types based on sizes. The results are presented in 3.5, 3.6, 3.7. The colors green, light green, yellow and red indicate how well the technology is suited. The stars represent the extent to which the technology can be implemented, whereas one star represents that the technology is barely implemented, while three stars represent that the technology is implemented. The report has divided the ships into sizes considering the overall length (LOA). Ships under 70 meters are considered small, middle ships are between 70 and 150 meters, and ships above 150 meters are considered large.

Table 3.5: Ships below 70m LOA [15]

2050, Ships below 70m LOA						
Ship type	**Bio-fuel**	**E-Methanol**	**LNG/LPG**	**H2/NH3**	**Full electric**	**plug-in hybrid**
Bulk carrier	**	**	**	**	*	**
General cargo ships/ RoRo ships Container ship	**	**	**	**	*	***
Passenger ships	**	**	**	**	***	***
Cruiseship	**	**	**	*	*	***
Service ships	**	**	**	**	**	***
Tug	**	**	**	**	**	***
Fishing vessels	**	**	**	**	**	***

Table 3.6: Ships between 70-150m LOA [15]

2050, Ships between 70-150 m LOA						
Ship type	**Bio-fuel**	**E-Methanol**	**LNG/LPG**	**H2/NH3**	**Full electric**	**plug-in hybrid**
Bulk carrier	**	**	**	**	*	**
General cargo ships/ RoRo ships Container ship	**	**	**	**	*	***
Passenger ships	**	**	**	**	**	***
Cruiseship	**	**	**	*	*	***
Service ships	**	**	**	**	**	***
Tug	**	**	**	**	**	***
Fishing vessels	**	**	**	**	**	***

Table 3.7: Ships above 150 m LOA [15]

2050, Ships above 150 m LOA						
Ship type	**Bio-fuel**	**E-Methanol**	**LNG/LPG**	**H2/NH3**	**Full electric**	**plug-in hybrid**
Bulk carrier	**	**	**	**	*	**
General cargo ships/ RoRo ships Container ship	**	**	**	**	*	***
Passenger ships	**	**	**	**	*	***
Cruiseship	**	**	**	*	*	***
Service ships						
Tug						
Fishing vessels						

According to the source, bio-diesel, e-methanol, and LNG/LPG are technically possible for all the ship's segments in 2050. Full-electric ships are most feasible for small passenger ferries, but they can also work on other ship types. However, using a plug-in hybrid solution makes electricity feasible for all sizes and vessel types. The use of hydrogen and ammonia is sat to be technically possible but complicated. Overall, hydrogen and ammonia as fuel are rated with two stars, indicating that is implemented. Furthermore, it is worth mentioning that the implementation of e-methanol is considered possible for all ship types and sizes [15]. In the presented prediction, it is assumed that it don't exist any service ships, tugs or fishing vessels above 150 m LOA, market with grey squares in the table 3.7.

Prediction of the future fuels presented by the port of Oslo

[8] discusses the applicability of compressed hydrogen for different vessel types. The article suggests that compressed hydrogen is well-suited for small general cargo ships and short-haul shipping operating on fixed routes with a size under 4,000-5,000 gross tonnage (GT). It is also suitable for speedboats, fast ferries, and tugboats utilizing a hybrid system of both batteries and hydrogen. Regarding liquid hydrogen, it is mentioned that there are no significant technical limitations. However, for larger ships with high energy consumption, the size and weight of the hydrogen storage tank may become impractical compared to conventional fuel options.

Prediction of the future fuels presented by the Norwegian Environmental Agency

[29] conducted an analysis of the future power demand of the transport sector in 2050 if alternative fuels were implemented. Table 3.8 presents the expected distribution of different energy carriers in the maritime sector by 2050. It is predicted that a high percentage of the vessel category domestic shipping and fishing will be electrified while compressed hydrogen, ammonia/ methanol, synthetic fuel, and biofuel will be used as alternative fuels.

Table 3.8: Dividing of the different energy carriers for the maritime sector in 2050 [29]

	Domestic shipping	**Fishing**
Battery electric	40 %	30 %
Hydrogen electric with compressed hydrogen, (fuel cell and electric engine)	15 %	10 %
Green ammonia in combustion engine	20 %	30 %
Green ammonia in fuel cell	5 %	10 %
Synthetic fuel	10 %	10 %
Biofuel	10 %	10 %

Summary

The majority of the analyses conducted in the maritime sector indicate a preference for battery systems and pure electricity whenever technically feasible. This is particularly applicable to small vessels that operate over short distances and frequently travel between regular ports. Furthermore, considering middle-sized vessels that cover longer distances and require higher energy capacities, the use of hydrogen becomes a more viable alternative. Hydrogen fuel cells offer a higher energy density and longer endurance, making them suitable for powering vessels with greater energy demands.

Lastly, for the largest ships that undertake the longest voyages without regular refueling opportunities, ammonia or methanol fuels are often recommended. These fuels, provide a higher energy density and are more suitable for sustaining the energy needs of larger vessels over extended periods. The storage and transportation characteristics of ammonia and methanol make them favorable options for these larger, long-distance ships.

Chapter 4

Mathematical Formulation of the Optimization Problem

In this master thesis, two slightly different optimization problems were developed. The first optimization problem, "Optimal operation", minimizes the electricity costs in a zero-emission port considering shore power load, charge power load, solar power production, and production of green hydrogen through electrolysis. The second optimization problem, "Operation and investment optimization," in addition to the first optimization problem, includes the investment cost of the electrolyser, hydrogen storage and transformer based on capacities. Considering these costs, the additional objective is to determine the optimal sizes of the mentioned parameters while ensuring that the entire load is covered.

The first optimization problem, "Optimal operation" will be used later in this master thesis to demonstrate the different possibilities and functions of the model. The second optimization model, "Operation and investment optimization" is used for analyzing different scenarios which consider different fuel mixes of a zero-emission port. Therefore, this chapter goes through some mathematical formulations which include; Assumptions, Notations, Mathematical model formulation, Description of constraints and objective functions.

4.1 Assumptions

To simplify the optimization problem some assumptions have been made:

- Data from earlier years are used to simplify the hourly load demand and solar production. This means that it is not implemented a forecast algorithm in this model. Therefore, the results consist of some uncertainties.
- To simplify, in this simulation is assumed unlimited capacity in the grid. However, a max capacity in the installed transformer in the port is assumed to represent the available capacity in the simulated port.
- The efficiencies regarding the transformer and the hydrogen storage are not included in this simulation.

4.2 Notations

Sets:
T - Set of time periods, t $\in$ T
M - Set of months, m $\in$ M

Index
t - hours, t $\in$ 1,2,...,8760
m -month, m $\in$ 1,2,...,12

System parameters:
$P_{pv,t}$ - Solar production [kW]
$P_{sh,t}$ - Shore power demand [kW]
$P_{ch,t}$ - Charge power demand [kW]
$H_{demand,t}$ - Hydrogen demand [kg]
$H^{max}_{storage}$ - Maximum hydrogen storage capacity at the port [kg]
$H^{min}_{storage}$ - Minimum hydrogen storage capacity [kg]
$H^{start}_{storage}$ - Start value of the hydrogen in the storage [kg]
$H^{end}_{storage}$ - End value of the hydrogen in the storage [kg]
$H^{startcap}_{storage}$ - Start capacity of the hydrogen storage [kg]
P^{max}_{ely} - Maximum capacity of the electrolyser [kW]
P^{min}_{ely} - Minimum capacity of the electrolyser [kW]
$P^{startcap}_{ely}$ - Start capacity of the electrolyser [kW]
P^{max}_{trafo} - Maximum capacity of the transformer [kW]
P^{min}_{trafo} - Minimum capacity of the transformer [kW]
$P^{startcap}_{trafo}$ - Start capacity of the transformer [kW]
η_{ely} - Efficiency factor of the electrolyser
f_{ely} - Calculation factor [kg/kW]

Economic parameters
$C_{el,t}$ - Electricity price [NOK/kWh]
$C_{fixed,m}$ - Fixed electricity price [NOK/month]
$C_{peak,t}$ - Cost of the peak hour each month [NOK/kWp/month]
$C_{storage}$ - Investment cost for hydrogen storage [NOK/kg]
C_{ely} - Investment cost for electrolyser [NOK/kW]
C_{trafo} - Investment cost for a new transformer [NOK/kW]

System variables
$P_{grid,t}$ - Power bought from the power grid [kW]
$P_{peak,m}$ - Power peak of each month [kW]
$P_{load,t}$ - Total load per hour [kW]
$H_{storage,t}$ - Level of hydrogen in the storage per hour [kg]
$P_{ely,t}$ - Power used to produce hydrogen in the electrolyser [kW]
$H^{cap}_{storage}$ - Extra storage capacity needed to fulfill the demand [kg]
P^{cap}_{ely} - Extra capacity the electrolyser needs to fulfill the demand [kW]
P^{cap}_{trafo} - Extra capacity the new transformer station needs to fulfill the demand [kW]

4.3 Mathematical Model Formulation

The two optimization problems minimize the electricity cost of operating a seaport that considers supplying enough electricity to cover the demand of shore power to all ships in port, charging power to full-electric or plug-in hybrid electric vessels, and local production of green hydrogen to cover the hydrogen demand for ships. Additionally, the problems consider energy production from solar power and peak shaving. The mathematical formulations of the two optimization problems are presented in this section, followed by a detailed explanation of the objective functions and constraints in the next section 4.4.

Optimal operation
The first optimization problem, "Optimal operation (Opc)", minimizes the operation cost of a seaport. The model formulation including the objective function and constraints, is shown in

(4.1):

$$
\begin{aligned}
& min \sum_{t \in T} C_{el,t} \cdot P_{grid,t} + \sum_{m \in M} (C_{peak,m} \cdot P_{peak,m} + C_{fixed,m}) \\
& st: \\
& P_{pv,t} + P_{grid,t} = P_{load,t} \\
& P_{load,t} = P_{sh,t} + P_{ch,t} + P_{ely,t} \\
& H_{storage,t} = H_{storage,t-1} - H_{demand,t-1} + P_{ely,t-1} \cdot f_{ely} \\
& P_{grid,t} \leqslant P_{trafo}^{\max} \\
& P_{ely}^{min} \leqslant P_{ely,t} \leqslant P_{ely}^{max} \\
& H_{storage}^{min} \leqslant H_{storage,t} \leqslant H_{storage}^{max} \\
& H_{storage,t=1} = H_{storage}^{start} \\
& H_{storage,t=8760} = H_{storage}^{end} \\
& P_{peak,m} \geqslant P_{grid,t} \qquad \forall t \in M
\end{aligned}
\tag{4.1}
$$

Operation and investment optimization
The model formulation for the second optimization problem, "Operation and investment optimization (Opinv)" slightly differs from the formulation of the first optimization problem with some additional variables and parameters in the constraints and objective function. The complete model is presented in (4.2), where the three last constraints differ from the first optimization problem.

In "Opinv", the parameters $P_{trafo}^{startcap}$, $P_{ely}^{startcap}$ and $H_{storage}^{startcap}$ are considered the capacities of already existing transformers, electrolyser, and hydrogen storage at the port. If there are no existing capacities at the port, these parameters are assigned a value of zero. To determine the optimal capacities required to meet the load demand at the lowest cost, it is introduced new parameters: P_{trafo}^{cap}, P_{ely}^{cap}, and $H_{storage}^{cap}$, which serve as slack variables. These parameters are adjusted to find the optimal capacities for the system, taking into account the load requirements and the associated costs.

Furthermore, the investment costs of the transformer, electrolysis and hydrogen storage are included in the objective function. To get a precise prediction for the total cost of the optimization problem the investment costs and the annual operation costs must be put into a relation to each other. Therefore, a simulation over a long time period, which pays attention to each of the expected running times of the single elements, needs to be done. Moreover, further economic, and technical information are needed as explained in 2.6. On the economic side explicit details about the future development of the electricity price as one of the main parameters in the optimization model are required. Chapter 2.2.6 has demonstrated unstable prices over the last five years and predictions for the next 10+ years are insecure. On the technical side, there are lot of uncertainties regarding the development of technologies in the hydrogen sector and if or how fast it will take the leading role in the energy market or the maritime sector. In consideration of all these unknowns, a precise prediction is not possible. Furthermore gathering all this information together is beyond the main focus of this master thesis.

Therefore, the investment costs are seen as a one-time payment in the first year, which accordingly is not considering the lifetime of the components, due to both the uncertainties presented in 2.6 and the various information regarding lifetimes. Thus, the investment costs will be weighted higher in the objective function than the operation cost. Nevertheless, the investment costs are mainly used to get a first impression of which impact they have on the optimization problem and if they are able to determine the right size and capacities of the components. For an appropriate analysis of the objective value, the cost will be split up into the annual operation cost and the total investment cost later on.

$$
\begin{aligned}
& min \sum_{t \in T} C_{el,t} \cdot P_{grid,t} + \sum_{m \in M} (C_{peak,m} \cdot P_{peak,m} + C_{fixed,m}) \\
& \qquad + H^{cap}_{storage} \cdot C_{storage} + P^{cap}_{ely} \cdot C_{ely} + P^{cap}_{trafo} \cdot C_{trafo} \\
& st: \\
& P_{pv,t} + P_{grid,t} = P_{load,t} \\
& P_{load,t} = P_{sh,t} + P_{ch,t} + P_{ely,t} \\
& H_{storage,t} = H_{storage,t-1} - H_{demand,t-1} + P_{ely,t-1} \cdot f_{ely} \\
& H_{storage,t=1} = H^{start}_{storage} \\
& H_{storage,t=8760} = H^{end}_{storage} \\
& P_{peak,m} \geqslant P_{grid,t} \qquad \forall t \in M \\
& P_{grid,t} \leqslant P^{startcap}_{trafo} + P^{cap}_{trafo} \\
& P^{min}_{ely} \leqslant P_{ely,t} \leqslant P^{startcap}_{ely} + P^{cap}_{ely} \\
& H^{min}_{storage} \leqslant H_{storage,t} \leqslant H^{startcap}_{storage} + H^{cap}_{storage}
\end{aligned}
\tag{4.2}
$$

4.4 Description of the constraints and objective functions

4.4.1 Objective functions

In this subsection, the objective functions for both optimization problems are presented and explained. The goal of an optimization is finding the best solution, specifically in this work to minimize the so-called costs "J". Therefore, very simplified, the gradients of the costs are calculated and subtracted from the original costs. By repeating this process the objective value converges step by step into a minimum. Based on this (basic) idea more advanced algorithms were developed and made publicly available to enable solving more complicated optimization problems. For this master thesis, the "Gurobi" solver was used and the problem was coded in the programming language Phyton.

Objective function for the "Optimal operation"
The first objective function, "J_{Opc}" minimizes the operation cost in the port based on the electricity prices. This objective function is included in both optimization models and is presented below:

$$J_{Opc} = \sum_{t \in T} C_{el,t} \cdot P_{grid,t} + \sum_{m \in M} (C_{peak,m} \cdot P_{peak,m} + C_{fixed,m}) \tag{4.3}$$

The first part of the objective function calculates all the power purchased from the grid per hour, multiplied by the corresponding electricity price for that hour. The electricity price, $C_{el,t}$, includes the day-ahead price per hour, plus a fixed energy tax. By minimizing this cost, the hydrogen production process aims to prioritize production during periods of lower electricity prices. This leads on the one hand to cost savings which are beneficial for the port and on the other hand to load shifting which is advantageous for the power grid. The second part of the objective function calculates the cost of the highest power peak during each month of the year. The cost, $C_{peak,m}$ varies between two prices during the winter and summer seasons. This part forces the problem to keep the peaks as low as possible, and therefore not produce all hydrogen possible in the hour with the lowest day-ahead price. Finally, a fixed electricity cost $C_{fixd,m}$, which is a part of the grid tariff, is included. It remains fixed throughout the year.

Objective function for the "Operation and investment optimization"
The second objective function aims to minimize the cost of port operation while accounting for the investment cost of hydrogen storage, the capacity of the electrolyser, and the expenses involved in constructing a higher-capacity transformer. By introducing the new variables; $H^{cap}_{storage}$, P^{cap}_{ely} and P^{cap}_{trafo}, the model achieves optimal capacities for each variable while ensuring that the load is covered at the most affordable price.

$$J_{Opinv} = J_{Opc} + (H^{cap}_{stoarge} \cdot C_{storage} + P^{cap}_{ely} \cdot C_{ely} + P^{cap}_{trafo} \cdot C_{trafo}) \tag{4.4}$$

4.4.2 Constraints

This subsection introduces the constraint of the minimization problems. The so-called constraints are the limitations of an optimization problem and are setting the framework in which the algorithm can operate and converge. The overall standing constraint to both optimization problems is that all parameters are defined as non-negative.

Power balance
The primary objective is to guarantee that the total power demand of the system is continuously met. To achieve this goal, the power balance equation, as represented by Constraint 4.5, must be satisfied. This equation indicates that the sum of the power purchased from the grid, ($P_{grid,t}$), and the power generated by the solar panels, ($P_{pv,t}$) must be equal to the total load of the system, $P_{load,t}$, for each hour. By adhering to this constraint, the system can effectively meet its power demands while ensuring a stable power supply.

$$P_{\text{pv},t} + P_{grid,t} - P_{load,t} = 0 \tag{4.5}$$

Where:

$$P_{load,t} = P_{sh,t} + P_{ch,t} + P_{ely,t} \tag{4.6}$$

The power bought from the power grid is a variable, while all the loads and the PV production are given as parameters. Hourly loads are determined by a Python script that takes a port log and its location into account. The demand is computed based on the ship's characteristics such as type, size (GT), average distance, and time spent in the port. The method for calculating the load demand in this thesis is further explained in chapter 5.

Because this master thesis is focusing on optimizing from the side of the port, in this simulation unlimited capacity in the power grid is assumed. Nevertheless, the capacity of the installed transformer is limiting the maximum power that can be bought from the power grid. This relation results in 4.7. Furthermore, this constraint leads also to reducing the power peaks and therefore enables peak shaving.

$$P_{grid,t} \leqslant P_{trafo}^{\max} \tag{4.7}$$

Hydrogen production
In order to guarantee the supply of hydrogen to ships in port, the hydrogen storage capacity must be sufficient to meet the demand at all times. Equation 4.8 shows how the hydrogen level for a certain hour depends on the hydrogen level in storage, demand, and produced hydrogen in the previous hour. The previous production is calculated by the product of the electrolyser's power consumption and efficiency factor n_{ely} divided by the lower heat value LHV of hydrogen.

$$H_{storage,t} = H_{storage,t-1} - H_{demand,t-1} + P_{ely,t-1} \cdot f_{ely} \tag{4.8}$$

where

$$f_{ely} = \frac{\eta_{ely} \cdot 1h}{LHV} \tag{4.9}$$

The hydrogen storage is limited in 4.10 by the minimum and maximum storage capacity. Additionally, the model includes an optional start and end value for the hydrogen storage level ($H_{storage}^{start}$ and $H_{storage}^{end}$). The $H_{storage}^{start}$ parameter in 4.11 is included to prevent high power peaks at the beginning of the year when the model strives to produce all required hydrogen for the first ships in port, due to the lack of pre-produced hydrogen in the storage. The end value $H_{storage}^{end}$ in 4.12 is included to ensure that the hydrogen level at the end of the period meets the starting value. Thus the hydrogen demand in the optimization problem is exactly covered by the hydrogen production in the simulated time period.

$$H_{storage}^{min} \leqslant H_{storage,t} \leqslant H_{storage}^{max} \tag{4.10}$$

$$H_{storage,t=1} = H_{storage}^{start} \tag{4.11}$$

$$H_{storage,t=8760} = H_{storage}^{end} \tag{4.12}$$

Furthermore, the electrolyser's capacity imposes a limit on the amount of hydrogen that can be produced per hour. This restriction significantly affects the system, and a greater capacity would enable more hydrogen production during hours with lower electricity prices.

$$P_{ely}^{min} \leqslant P_{ely,t} \leqslant P_{ely}^{max} \tag{4.13}$$

Investment constraints
In "Opinv", the parameters of the maximum capacities of the existing transformer, electrolysis and hydrogen storage (P_{trafo}^{max}, P_{ely}^{max} and $H_{storage}^{max}$) are replaced in 4.14, 4.15 and 4.16 with parameters representing the initial values ($P_{trafo}^{startcap}$, $P_{ely}^{startcap}$ and $H_{storage}^{startcap}$). These start parameters consider the capacities of already existing transformers, electrolysers, and hydrogen storage at the port. If there are no existing capacities at the port, these parameters are assigned the value zero. To determine the optimal capacities required to meet the load demand at the lowest cost, new parameters are introduced: P_{trafo}^{cap}, P_{ely}^{cap}, and $H_{storage}^{cap}$, which serve as optimizable variables. These parameters are adjusted to find the optimal capacities for the system, taking into account the load requirements and the associated costs.

$$P_{grid,t} \leqslant P_{trafo}^{startcap} + P_{trafo}^{cap} \tag{4.14}$$

$$P_{ely}^{min} \leqslant P_{ely,t} \leqslant P_{ely}^{startcap} + P_{ely}^{cap} \tag{4.15}$$

$$H_{storage}^{min} \leqslant H_{storage,t} \leqslant H_{storage}^{startcap} + H_{storage}^{cap} \tag{4.16}$$

Chapter 5

Models and Input Parameters

The model of this master thesis consists of three Python scripts which will be referred to as the "Optimization Model", "Load Model" and "Electricity Price Model", where the Load Model and Electricity Price Model provide input data to the Optimization Model. Figure 5.1 illustrates the input and output parameters for the complete model.

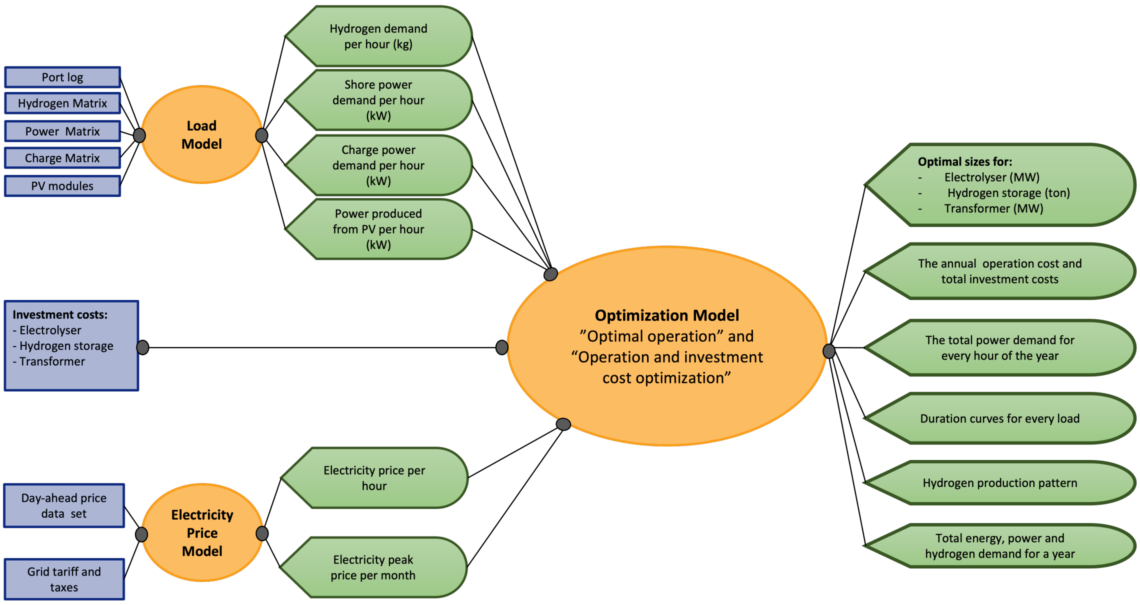


Figure 5.1: Overview of the input and output data between the "Load Model", "Electricity Price Model" and the "Optimization Model"

The "Optimization Model" includes different loads and inputs which are calculated in their own Python scripts. The determination of the shore power load and the power production from the photovoltaic system per hour is based on the Python script developed in [92] and is called the "Load Model". Notably, the script was expanded within this master thesis to include the calculation of hydrogen load demand and charging power demand for both full-electric and plug-in hybrid ships for each ship segment per hour the ship lay in the quay. For the code to calculate the load a lot of the work included finding and calculating the input matrices representing the hydrogen load demand and charge power demand for the different ship segments. Moreover, the "Electricity Price Model" has been developed to estimate the electricity price per hour and per month based on data from both [44] and [43]. The "Optimization Model" uses the output parameters from the two mentioned Python scripts together with the investment costs of electrolysis, hydrogen storage, and transformer to determine all the outcomes presented in figure 5.1. The outcomes are as presented in figure 5.1 the operation costs, hydrogen demand, energy demand and power peaks. All these quantities are also available as vectors with their hourly values in order to analyze the time course in more detail. For the Opinv-minimization, there are also returned the optimal capacities for the electrolyser, transformer and hydrogen storage.

5.1 Overview of Input Parameters and Assumptions

The Optimization Model has been designed to be highly adaptable and can be employed in various port locations. To use the program, certain input data is required, which can be customized based on the port of interest. The following list outlines the necessary input data to run the models.

List of input parameters and data to the models

- **Input parameters and data for the "Load Model":**
  - Port log: The port log must include the arrival time, departure time, ship type, quay area, and ship size.
  - PV data: Based on the location of the port of interest, the matching power production from solar power of that area can be chosen. Furthermore, the number of installed PV modules is optional.
  - Load demand matrices: The load per hour is calculated based on the hydrogen, charge and power matrices, which consider the hydrogen, charge power and shore power demand respectively for all ship segments.
- **Input data for the "Electricity Price Model":**
  - Day-ahead price
  - Grid tariff
- **Additional input data for the "Optimization Model":**
  - Investment costs of the electrolyser, hydrogen storage and transformer

Furthermore, two assumptions have been made in this master thesis and implemented in the script, for the case study.

Assumptions in the "Load Model"

1. Every vessel that stays under 1 hour in port is filtered out in this simulation. This is mainly because the optimization model is set to have a one-hour time step. However, the "Load Model" is organized so that the time step can be chosen by the analyst.
2. Other ship types than the ones included in the load demand matrices: (hydrogen matrix, charge matrix and power matrix) are assumed to be "Other activities" in the Load Model.

5.2 Load demand matrices

This subsection presents four tables representing hydrogen demand, shore power demand and charge power demand for fully electric ships and plug-in hybrid ships, categorized by ship types and sizes. A ship type of a given size can be referred to as a ship segment. The data presented in the hydrogen matrix (5.2) and the power matrix (5.4) are presented in [93]. The tables have also been used in calculations made by [8]. The data in the tables (5.2 and 5.4) are based on comprehensive information on the amount of fuel each ship in Norway used in 2014 [94]."Each ship segment is represented by an average ship, characterized by average main engine size, fuel consumption in port, domestic and international traffic, fuel consumption on main/auxiliary engines, fuel consumption in transit and maneuvering, among others" [93]. The mentioned tables are used as input data for the optimization problems. The size categories 1 to 7 represents the size given in gross tonnage (GT) and are shown in table 5.1.

Table 5.1: Size category description

	<= 999 GT	1000-4999 GT	5000-9999 GT	10 000-24 999 GT	25 000- 49 000 GT	50 000- 99 999 GT	>= 100 000 GT
Size category	1	2	3	4	5	6	7

The term "gross tonnage (GT)" refers to the volume of all occupied, enclosed areas aboard a ship and is used as a measurement for the size of a ship [8]. The formula used to calculate the gross tonnage of a ship is shown in appendix D.

5.2.1 Hydrogen demand

The estimated hydrogen consumption per shipping segment (measured in tonnes per trip) is shown in the hydrogen matrix (table 5.2). The hydrogen demand per trip is estimated based on the average fuel consumption per ship segment and the number of port calls in Norway in 2014 [93]. The colors in the table illustrate together with the presented fuel consumption which ship segments are feasible (green) and not feasible (red) for hydrogen-based propulsion. In general, bigger ships consume more fuel than smaller ships. However, it is worth mentioning, that based on this data set, some exceptions appear to this pattern inside the segments [93]. Size category 3 for fishing vessels and size category 5 for "Other activities" are considered unfeasible for hydrogen since the hydrogen demand would be too high to handle onboard these ships. The ship segments without any data represent that there were no ships registered in those sizes.

Table 5.2: Average hydrogen demand (tons) per ship segment per trip [93]

Ship type	Size category						
	1	2	3	4	5	6	7
Oil tankers	4	14	17	67	40	61	111
Chemical/product tankers	2	8	16	26	31		
Gas tankers	2	6	18	28	27	106	169
Bulk carriers	2	8	9	24	40	47	26
General cargo ships	1	7	15	37	14		
Containership	1	2	6	4			
RoRo cargo	2	46	7	17	7	16	
Reefer/freezer ships	8	22	37				
Offshore supply ships	7	19	57				
Other offshore service	4	14	54	116	31		
Fishing vessels	4	31	286				
Other activities	2	15	63	197	541		

The Python script, Load Model, utilizes this table to compute the hydrogen requirement per ship upon arrival at the quay. The cumulative hydrogen demand is distributed across the duration of the ships' stay in the port, ensuring a consistent supply of hydrogen throughout the hours. This means that for an oil tanker ship of size category 1 which remains at the quay for four hours, the hydrogen demand per hour is estimated to be one ton.

5.2.2 Shore power demand

The power matrix presented in table 5.3, displays the estimated shore power demand for the different ship segments [7]. In contrast to the hydrogen table 5.2, the power matrix also includes the ship type "Passenger ships". The power demand increases per size category for all the ship types.

Table 5.3: Estimated shore power demand per ship size and type given in (kW) [7]

Ship type	Size category						
	1	2	3	4	5	6	7
Oil tankers	37	161	352	476	646	834	1032
Chemical/product tankers	106	289	531	723	864	1434	1536
Gas tankers	111	254	667	836	1078	2816	3556
Bulk carriers	26	80	132	197	261	350	438
General cargo ships	12	66	149	259	416	579	704
Containership	31	121	332	473	864	1535	2295
RoRo cargo	28	94	213	415	529	668	736
Reefer/freezer ships	44	153	319	542	672	800	960
Passenger ships	20	119	272	570	1194	2100	2912
Offshore supply ships	45	144	345	553	912	1144	1248
Other offshore service	42	149	251	417	575	643	685
Fishing vessels	43	149	284	454	454	454	454
Other activities	28	173	344	569	988	1282	1600

5.2.3 Charge power

Full-electric ships
To estimate the energy and power requirements for full-electric ships, data from the hydrogen table 5.2 is utilized. The calculation process from hydrogen demand to energy demand for a ship's propulsion is illustrated by equation 5.1. It should be noted that the hydrogen demand utilized in the calculation represent the actual demand needed to propulsion of a hydrogen ship. The efficiency level of the fuel cell technology may vary, as discussed in subsection 2.1.2. However, this conversion calculation considers a PEMFC with an efficiency of approximately 55% [28]. Additionally, the lower heat value of hydrogen, 33.33 kWh/kg, is utilized [22].

Since both, hydrogen and full electric ships, use an electric engine, the efficiency of the engine is not included in this calculation. The results of the calculations are presented in Table 2 in the appendix E.

$$E_{ch} = H_{demand} \cdot LHV_{H2} \cdot \eta_{fc} \tag{5.1}$$

where:
H_{demand} : Hydrogen demand (kg)
LHV_{H2} : Lower heat value of hydrogen (kWh/kg)
η_{fc} : Efficiency of the fuel cell
E_{ch} : Energy demand for propulsion of the ship (kWh)

Plug-in hybrid ships
The feasibility of full or partial electrification of different ship segments is subject to various conditions. The varying sailing distances make it challenging to determine the required battery size and level of hybridization. Automatic Identification System (AIS), a tracking technology onboard ships, provides data regarding capacity demand for each ship type and size. Based on this data from 6000 vessels, an estimate of the average energy consumption per trip per ship segment was created by [94]. However, it is important to note that there may be significant variations in energy use for many vessels within the same sector.

Table 5.4 presents the battery size and the corresponding coverage of energy demand for each ship segment. For instance, ships in size category 1 are assumed to use a 1000 kWh battery, while size category 2 uses a 2000 kWh battery, except for passenger ships, which use a 1000 kWh battery.

Size category 3 requires a battery size of 3000 kWh, and the remaining categories are assumed to use a 5000 kWh battery [94]. According to the research, an average passenger ship in size category 1 can be 100% covered by a battery of the size 1000 kWh. The rest of the segments colored in green is considered the best options for partial electrification.

Table 5.4: Estimated proportion of fuel consumption per trip, given in percentage, that could be covered by a battery, for an average ship in each shipping segment operating in Norwegian waters [93]

Ship type	Size category						
	1	2	3	4	5	6	7
Oil tankers	3	1	2	1	1	1	0
Chemical/product tankers	3	4	2	2	2		
Gas tankers	3	2	2	2	1	0	0
Bulk carriers	4	2	2	8	4	2	2
General cargo ships	17	5	2	4	4		
Containership	17	5	5	8			
RoRo cargo	8	5	6	4	5	2	
Reefer/freezer ships	1	3	6				
Passenger ships	133	36	19	5	1	1	1
Offshore supply ships	11	3	2				
Other offshore service	16	5	1	1	1		
Fishing vessels	11	1	0				
Other activities	30	4	1	1	0		

5.3 Further input data

This section provides the remaining input data required for the "Load Model", "Electricity Price Model", and "Optimization Model".

Input data for PV production
The input data for solar production is calculated based on estimation and measurement points allocated in 15 different places in Norway as explained in section 2.4. The analyst can freely choose the number of PV modules and the area of implementation.

Input data for the "Electricity Price Model"
The operation cost in the simulation will be calculated based on the hourly electricity price, the monthly peak price, and the fixed monthly price as presented in subsection 2.2.5.

The energy market has experienced unexpected price fluctuations over the last two years, as described in subsection 2.2.6. It is unclear whether these prices will continue to rise or if they will return to more typical conditions. The result from simulation based on the day-ahead prices from the last years can therefore be unsure. However, it will give an impression of what it may be like if prices remain high. Therefore the day-ahead prices from 2022, as presented in subsection 2.2.6 are chosen as input data for this simulation. Furthermore, the grid tariff which is presented in table 2.6 in subsection 2.2.5 is included in the simulation.

Additional input data for the "Optimization Model"

The chosen investment costs for electrolyser, hydrogen storage, and transformer are based on the literature presented in section 2.5.

Investment cost of the electrolysis
The studies referenced in subsection 2.5.1 provide varying estimations of the investment cost for different types of electrolysers. Nevertheless, in the further calculations of this master's thesis, an investment cost of 640 €/kW is assumed, comparative to the alkaline electrolyser in [58].

Additionally, this cost is within the price range of a PEM electrolyser, which is due to its flexibility characteristics very promising for hydrogen production in a port [57] [58].

Investment cost of the hydrogen storage
Table 2.10 displays the investment costs for compressed hydrogen, with prices ranging from 175 €/kg to 1829 €/kg. Nevertheless, the majority of sources report investment costs within the range of 400-600 €/kg. For the present study, the investment cost provided by [65] for compressed hydrogen will be used. The storage tank under consideration is designed to store hydrogen within the range of 900 to 5000 m^3, with an investment cost of 49 €/m^3. By utilizing the ideal gas law, which is represented by equation 2, the unit price is determined to be 545 €/kg. The chosen investment cost is based on several factors, such as the consideration of a larger storage capacity, the year of the source, and the concordance of multiple sources [65].

Investment cost of the transformer
Based on the different investment costs for a transformer, presented in subsection 2.5.3, a price of 240 NOK/kW is chosen. This is an estimated price, which is slightly above the cost function used in equation 2.7 in [69].

5.4 Summary of the input parameters

All the input data for the "Optimization Model" are summarized in table 5.5 and 5.6. It has been used a currency change factor where 1€ = 10 NOK.

Table 5.5: Economic parameters

Economic Parameter	Value
$C_{el,t}$	Day ahead prices + 0.03 (NOK/kWh)
$C_{peak,m}$	60 for winter (NOK/kWp/month) 25 for summer (NOK/kWp/month)
$C_{fixed,m}$	900 (NOK/month)
$C_{storage}$	5450 (NOK/kg)
C_{ely}	6400 (NOK/kW)
C_{trafo}	240 (NOK/kW)

Table 5.6: System and simulation parameters

System Paramter	Value	Simulation parameter	Value
$P_{sh,t}$	Based on Table 5.3	T	8760 h
$P_{ch,t}$	Based on Table 5.4	M	12
$P_{pv,t}$	Input data from 2015		
$H_{demand,t}$	Based on Table 5.2		
η_{ely}	0.67		
LHV	33.33 (kWh/kg)		

The optional system parameters are chosen by the analyst of the models. In this master thesis will the impact of some of the optional parameters be tested.

Table 5.7: Optional parameters

System Parameters for Opc	Value	System Parameters for Opinv	Value
$H_{storage}^{min}$, $H_{storage}^{max}$	optional	$H_{storage}^{startcap}$	optional
P_{ely}^{min}, P_{ely}^{max}	optional	$P_{ely}^{startcap}$	optional
P_{trafo}^{max}	optional	$P_{trafo}^{startcap}$	optional

Chapter 6

Case Study

This master thesis aims to calculate the future energy, power and hydrogen demand in a zero-emission port, in addition to optimizing the production pattern of green hydrogen based on the electricity prices. The simulated port includes local power production from solar panels and local production of green hydrogen through electrolysis. It is assumed that all the zero-emission ships will need shore power while lying in the quay. Additionally, it is assumed that ships either are hydrogen ships, full-electric ships, or plug-in hybrid electric ships.

The port of Oslo serves as an example for this case study. To examine the overall power demand, hydrogen demand, production cost, investment cost, and required capacities for electrolyser, hydrogen storage, and transformers to meet the demand, the simulation utilizes the port log from 2018. The general input data for the model was presented under the previous section 5.4 and is used in this case study.

6.1 Location

The port of Oslo is located at the heart of the Oslo Fjord and consists of the areas from the Filipstad port in the west to the Ormsund port in the east. The port of Oslo is considered to be the largest public cargo and passenger port of Norway and it is operated by the enterprise "Oslo Havn". This case study considers the east part of the port of Oslo, which consist of the following seven quay areas: Grønlia, Kongshavn, Søndre Bekkelagskai, Oljehavn - utstikker, Ormsund, Sjursøya and Kneppeskjærutstikker. The mentioned areas are located inside the red line in figure 6.1.

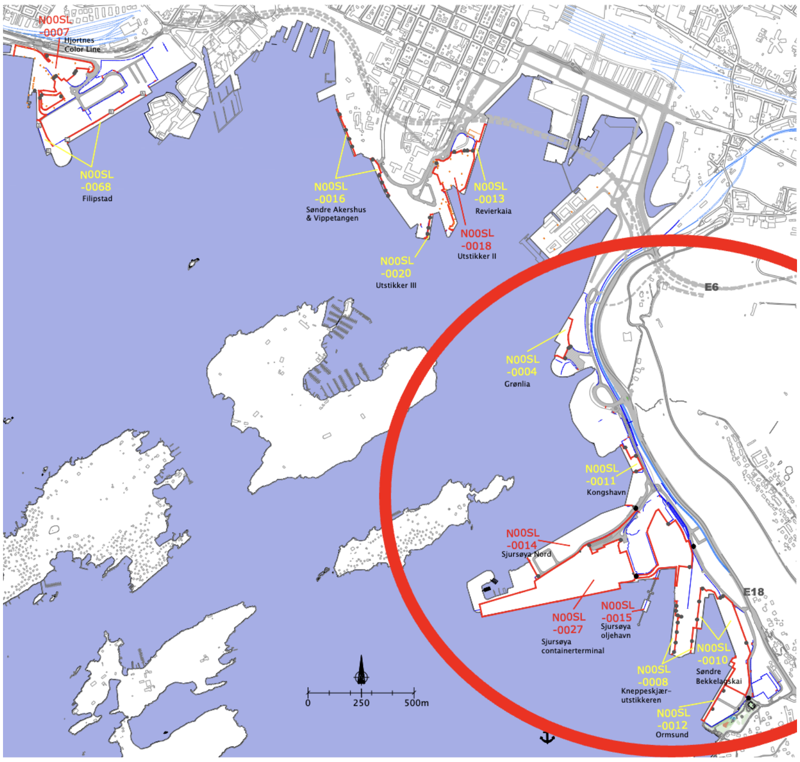


Figure 6.1: The location of the quay areas which are a part of the port of Oslo [95]

Table 6.1, presents the depth and length of each quay area. The total area is calculated to be 215400 m^2

Table 6.1: The area of the port of Oslo [96]

Quay area	Depth (m)	length (m)
Kongshavn, north	6	140
Kongshavn, south	5	160
Sjurøykaia, north	7-10	524
Sjursøykaia, south	7	500
Sjursøykaia, east	6	205
Bekkelagskai, north	6	182
Bekkelagskai, south	7.5	317
Kneppeskjærsutstikkeren	6.5	238
Ormsundkaia	8	270
Oljehavn - utstikker	15	336

6.2 Analysis of the port log

The data set from the port of Oslo includes all the ships that called the port of Oslo during 2018. The information in the port log includes the ship types, ship name, ship size given in gross tonne (GT), exact arrival and departure time, and quay area. It was in total 2262 ships, of which 19 different ship types, arrived at the port in 2018. The sizes of the ships varied from 10 GT to 29874 GT, meaning from ship size category 1 to 5. Table 6.2 provides an overview of the number of arrivals in each quay area as well as the most common ship types. In 2018, the quays Sjursøya and Kongshavn received the most arrivals with 921 and 623, respectively.

Table 6.2: Number of arrivals and the number of unique ship types per quay area of the port of Oslo in 2018

Quay area	**Number of arrivals**	**Unique ship types**	**Ship type with most arrivals**
Sjursøya	921	7	Container ship: 495 General cargo: 268
Kongshavn	623	7	General cargo: 566
Oljehavn - utstikker	231	3	Oil tankers: 158
Grønlia	150	12	General Cargo: 50
Kneppeskjærutstikker	136	3	Car carrier: 70 General cargo: 65
Søndre Bekkelagskai	130	4	Tug: 126
Ormsund	71	7	Oil tankers: 28
TOTAL	**2262**	**19**	

The ship types that arrive most at the port of Oslo are general cargo ships, container ships and tugs. Together, these three ship types make up 73 % of all arrivals at the port. An overview of the different ship types and the number of arrivals are shown in figure 6.2.

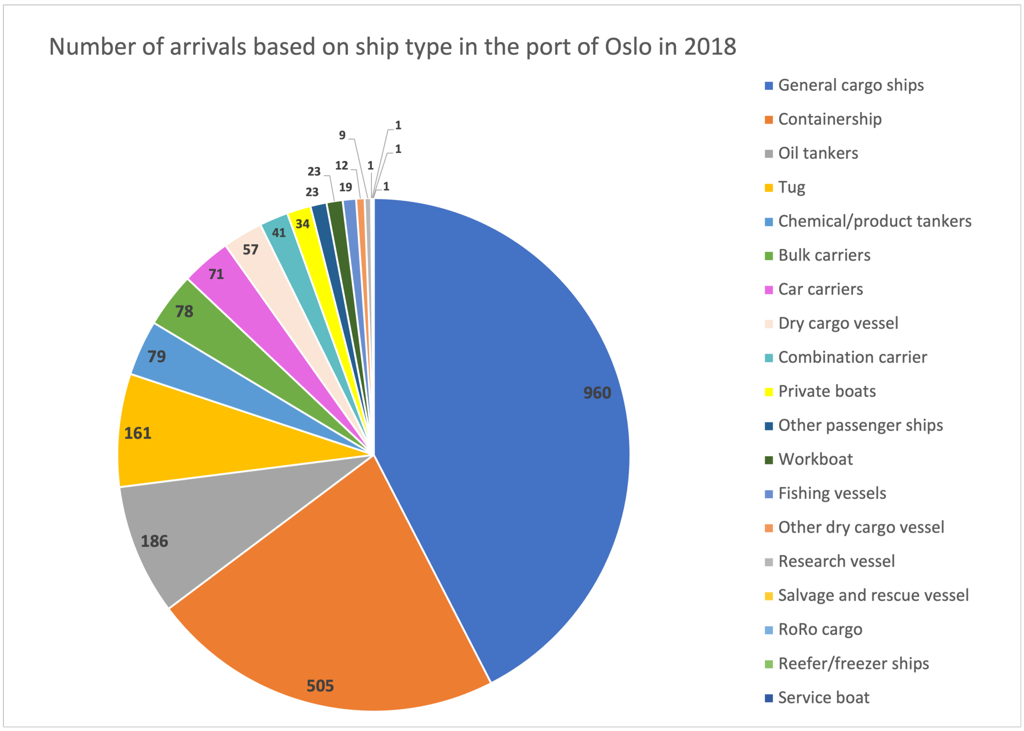


Figure 6.2: Overview of the ship types and number of arrival at the port of Oslo in 2018

The number of ships in each ship category:

Table 6.3: The number of ships in each ship category

	<= 999 GT	1000-4999 GT	5000-9999 GT	10 000-24 999 GT	25 000- 49 000 GT	50 000- 99 999 GT	>= 100 000 GT
Size category	1	2	3	4	5	6	7
Number of ships	653	731	604	265	9	0	0

Some of the ship types introduced in figure 6.2 are not included in table 5.2, 5.3 and 5.4 of section 5.1 which represents the different energy and hydrogen demand per ship segment. Therefore, in the following simulations, it is assumed that the missing ship types will adopt the demands of a ship type that can be considered equivalent. Table 6.4 presents these assumptions.

Table 6.4: Assumption regarding the ships types from the port of Oslo which not matches the input tables 5.2, 5.3 and 5.4

Ship type in the port of Oslo	Ship type in the input tables	Justification
Tug	Other offshore service ships	The ship types have similar functions. Additional, the tugs arriving at the port of Oslo are all in size category 1. This distribution is similar to the other offshore service ships statistic presented by [94].
Car carriers	RoRo cargo	A RoRo cargo also known as roll-on/roll-off ships are designed to transport wheeled cargo such as cars, motorcycles, trucks, semi-trailer trucks, buses, trailers, and railroad cars. This type of cargo is typically driven onto and off the ship using its own wheels or a platform vehicle like a self-propelled modular transporter[4]. Therefore, car carriers will be considered as RoRo cargo in this simulation.
Dry cargo vessel	Bulk ship	Bulk ship is a sort of dry cargo vessel [4]
Other dry cargo vessel	Bulk ships	Bulk ship is a sort of dry cargo vessel [4]
Combination carrier	Average of the numbers from general cargo and bulk carrier	The combination carrier is a combination between the two mentioned types.
Other passenger ships	Other activities	The ships in the category "Other passenger ships" consist of 23 ships in sizes 98 to 181 GT. This represents really small ships and is, therefore, placed as other activities in this simulation. The same explanation can also justify why the following ship types will be considered as "Other activities" [94].
Workboat	Other activities	
Research vessel	Other activities	
Salvage and rescue vessel	Other activities	
Service boat	Other activities	
Private boats	Not included in the simulation	Note included since these boats are private

6.3 Transformer capacity in the port of Oslo

The port of Oslo consists today of 11 transformers with different capacities. Table 6.5 displays the current capacities in the different quay areas. The total transformer capacity is calculated by adding all the existing capacities together. Therefore, the total capacity of 36 715 kVA, represents the maximum capacity in the entire port of Oslo today [8].

Table 6.5: Transformer capacity in the quay areas of the port of Oslo [8]

Quay area	Transformer capacity
Søndre Bekkelagskai	500 kVA
Kneppeskjærutstikker	800 kVA + 2800 kVA
Kongshavn	1000 kVA + 1815 kVA + 1300 kVA
Sjursøya	7200 kVA + 1600 kVA + 14 000 kVA
Ormsund	2850 kVA
Grønlia	-
Oljehavn-utstikker	2850 kVA
Total	36 715 kVA

6.4 Summary of input parameters and assumptions

The implemented filtration due to short stays in the port presented in section 5.1 for the Load Model excludes 58 out of the 2262 arrivals in the port of Oslo. Furthermore, the 34 private boats are not included. Therefore, this case study is left with a total of 2170 arrivals in the port of Oslo.

The input parameters for this case study are derived from various sources and years, as outlined in section 5.4. For instance, the port log of Oslo is from 2018, the day-ahead price data is from 2022, and the measured solar irradiates and temperature data corresponding to 2015. These specific years were selected based on the availability of data for this master's thesis.

It is important to note that the port log of a given port changes annually due to vessel traffic, economic conditions and market competition. Consequently, the results obtained from this case study represent a random year and serve as an approximate outcome. The measured temperature and irradiation values will exhibit slight variations across different years. However, as described in 2.4, the power production from the chosen PV sources follows a logical curve, with higher production during summer months compared to winter months. Considering that the solar production in the port is relatively small compared to the power purchased from the grid, the measurements from 2015 are sufficient for this master's thesis purpose. Furthermore, the electricity prices from 2022 are utilized to demonstrate the potential operational costs if the current price trends continue as described in 5.3. Although there may be slight differences between the years, the chosen data sufficiently represents the analysis and modeling objectives of this master's thesis.

The port log of Oslo and the mentioned input data is firstly used to illustrate the functions of the "Optimal operation (Opc)" 4.3 and the "Operation and investment optimization (Opinv)" 4.3, to provide an understanding of how the models operate. Furthermore, Opinv is utilized to determine results considering six fuel mix scenarios that consider different fuel combinations of the zero-emission port. The scenarios will further be explained in section 7.3 and 7.4.

Chapter 7

Results

The results of this master thesis are mainly divided into two parts. The first part (in section 7.1 and 7.2) presents a validation of the mathematical concept of the two developed optimization models (4.1, 4.2) by testing values for different system parameters. Furthermore, the results in the first part illustrate how the different input parameters affect the simulated results. The second part utilizes the second optimization model, "Operation and investment optimization (Opinv)" for six created scenarios considering different fuel mixes using the port of Oslo as a case study. The related results for the second part are presented in section 7.3 and 7.4. The six fuel mix scenarios aim to provide the total energy, power, and hydrogen demand, in addition to the computed sizes of electrolyser, hydrogen storage and transformer if different green fuels (shore power, hydrogen and charge power for full-electric and plug-in hybrid) are used to power the ships of the port of Oslo. Again, hydrogen as fuel represents pure hydrogen, green ammonia and green methanol in this master thesis.

Scenario 6, titled "Steps to the Future" introduces a distinctive approach compared to the five other fuel mix scenarios outlined in this study and is presented in 7.4. The "Steps to the Future" scenario represent a three-step progression towards achieving a zero-emission port, with each step representing a gradual and realistic implementation of green fuel in the maritime sector. These steps illustrate the incremental growth in energy, power, and hydrogen demands, as well as the corresponding sizes of hydrogen storage, electrolysis, and transformer capacities required for each step.

In all tests and scenarios conducted in this master's thesis, the primary focus is to present key performance indicators. These indicators include the objective value, which consists of the annual operating costs and the total investment costs, as well as the total energy demand, the highest power peak of the system, and total hydrogen demand in a year. Additionally, the hydrogen production pattern, and capacities of the estimated electrolyser, transformer and hydrogen storage are presented for each scenario. Lastly, a load duration curve is utilized to demonstrate the duration of power demand during the year for each scenario.

All tests and scenarios in this master thesis use the general input parameters listed in section 5.4. The port log of Oslo is from 2018, the day-ahead price is from 2022 and the sun irradiance and temperature is from 2015 as described in 6.4. Furthermore, the first two sections (7.1 and 7.2) consider that all ships in port are fueled with hydrogen while the two next sections (7.3 and 7.4) consider different green fuel mixes.

7.1 Optimal operation

This subsection presents the result of the hydrogen production considering the "Optimal operation" model, with given limits of the transformer, electrolyser and hydrogen storage (P_{trafo}^{max}, P_{ely}^{max}, $H_{storage}^{max}$). This optimization problem can be utilized for ports where the limits of the mentioned parameters are already set. This approach results in a first approximation of how much the yearly production cost and total energy, power and hydrogen demand of the port would be. The outcome of this model may also indicate that the limits set are insufficient to meet the total demand of the specified port.

To illustrate the impact of the limits for the electrolyser, transformer and hydrogen storage (P^{max}_{ely}, P^{max}_{trafo} and $H^{max}_{storage}$) the model is simulated for four test scenarios. The sizes of the hydrogen storage increase for each test, while the capacities of the electrolysis and transformer remain constant. It is considered that all the ships in port are fueled with hydrogen, and not receiving any shore or charge power. The rest of the input data is presented in table 5.6 in section 5.4.

In the first scenario, the hydrogen storage ($H^{max}_{storage}$) is exactly big enough to store the maximum hydrogen demand the port experience in one hour (H^{max}_{demand}). Considering that the production of hydrogen due to its efficency requires 50 kWh/kg, the capacity of the electrolysis system given in kWh has been determined to be 50 times the highest hydrogen demand given in kg observed in one hour. Similarly, the capacity of the transformer has been set to be 60 times the maximum hydrogen demand in one hour. In the given test scenarios, where shore power and charge power are not included, the chosen capacity for the transformer ensures it is more than sufficient to accommodate the required capacity of the electrolysis system. As a result, the size of the hydrogen storage is the key parameter that influences the outcomes of the analysis. Table 7.1 presents the different sizes of the hydrogen storage tested for.

Table 7.1: Test scenarios of the hydrogen storage

	Test 1	Test 2	Test 3	Test 4
$H^{max}_{storage}$	H^{max}_{demand}	$5 \cdot \mathrm{H}^{max}_{demand}$	$10 \cdot H^{max}_{demand}$	$20 \cdot H^{max}_{demand}$

7.1.1 Comparison of test scenarios

Table 7.2 displays the outcomes for the four tests where the hydrogen storage varies, while the electrolysis and transformer capacities remain fixed at 1114.8 MW and 1337.8 MW, respectively. The hydrogen storage is equal to 22.3 tons in Test 1 and is increasing in the other scenarios based on the given factor. The highest power peak is increasing with every test until it reaches the maximum capacity of the electrolysis in Test 3. Beyond this point, the hydrogen storage size does not make any difference for the highest power peak. The increasing power peak in the previous tests occurs due to the surplus storage capacity, enabling the system to produce more hydrogen during the hours and months when the cost of production is lower. Therefore, it can be observed that the objective value, representing the total production cost, is reduced for each test.

Table 7.2: Result of the four test scenarios

Tests	**1**	**2**	**3**	**4**
Objective value (MNOK/year)	1772	1580	1352	1352
Total energy demand (GWh/year)	925	925	925	925
Highest power peak (MW)	804	966	1114.8	1114.8
Hydrogen storage (tons)	22.3	111.5	223.0	446.0
Electrolyser capacity (MW)	1114.8	1114.8	1114.8	1114.8
Transformer capacity (MW)	1337.8	1337.8	1337.8	1337.8

Figure 7.1 displays the hydrogen storage level and production pattern during each hour of the year for Test 1 and 4, respectively. The two plots to the left show the hydrogen demand (in red spikes), and the hydrogen storage level (in green). One noticeable difference between Test 1 and Test 4 is the variation in the hydrogen storage level. In Test 1, where the storage capacity is more limited, the storage level consistently fills up and depletes throughout the majority of the hours, as indicated by the compact green areas. On the other hand, Test 4, which has a storage capacity 20 times larger than Test 1, demonstrates a contrasting storage pattern. The storage level only

reaches its maximum capacity during specific hours of the year. These hours typically coincide with the periods of the year featuring the lowest day-ahead prices, highlighting the strategic utilization of the storage system.

The plots to the right in figure 7.1 illustrate the power loads of the system given in MW. Since only hydrogen is considered as fuel, the right plots illustrate the power demand for the production of hydrogen throughout the year. The production curves indicate that the lowest monthly peak in Test 1 is slightly above 200 MW, appearing in February (between hour 745 and 1416), while in Test 4, the lowest monthly peak is approximately 100 MW, appearing in March (between hour 1417 and 2160). The highest monthly peaks occur in May and September for Test 1, and in July and September for Test 4. Furthermore, the results from Test 4 illustrate that the model strives to produce more hydrogen in the summer months (the cheapest months) compared to Test 1 which is forced to produce hydrogen when the demand occurs. Again, this difference occurs because the model in Test 4, has more storage capacity and therefore is more flexible with the production times.

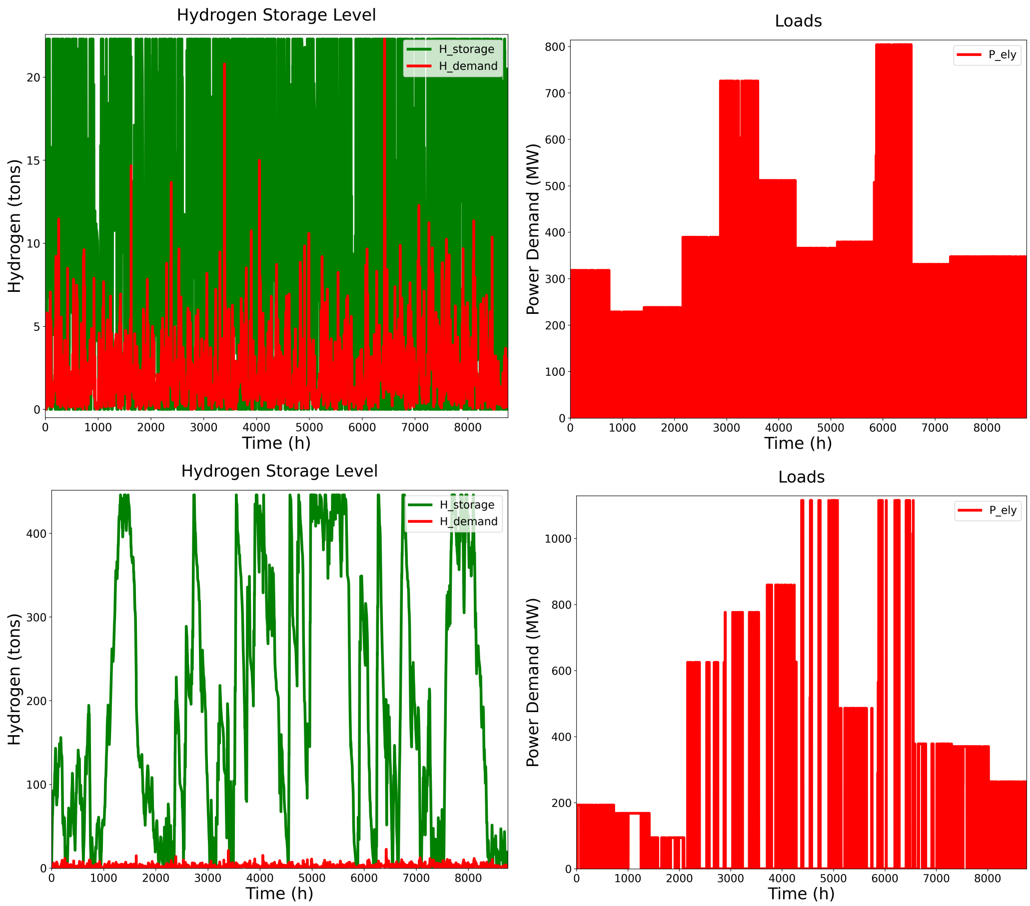


Figure 7.1: The plots to the left shows the hydrogen storage level and demand given in tons, while the plots to the right illustrate the power demands given in MW. Test 1 is presented in the upper plots while Test 4 is presented in the lower plots.

The conclusion of the given comparison is that the restriction parameters governing hydrogen storage, electrolyser capacity, and transformer capacity significantly impact each other and the model. The system produces more hydrogen in the cheapest hours of the year if the capacities of the electrolyser and hydrogen storage are large enough. Furthermore, with the different limits given, the optimization model chooses different times of the year to have high power peaks. The different hydrogen production pattern serves as evidence of the accuracy and effectiveness of the mathematical formulation used in the optimization problem.

7.2 Operation and investment optimization

The "Operation and investment optimization" deviates from the "Optimal operation" in two significant aspects. Firstly, it incorporates the investment costs for the electrolyser, hydrogen storage, and transformer, as elaborated in section 4.3. Secondly, the "Operation and investment optimization" considers the existing system's starting values for the electrolyser, transformer and hydrogen storage ($P_{ely}^{startcap}$, $P_{trafo}^{startcap}$, $H_{storage}^{startcap}$) in addition to find an optimized dimension for this components. This section presents the impact of the total investment costs and PV production. The general input data is shown in section 5.4, where the day-ahead prices are from 2022, and the port log is from the port of Oslo in 2018.

7.2.1 Impact of investment cost

To demonstrate the impact of investment costs ($C_{storage}$, C_{ely}, and C_{trafo}), Opinv was solved twice: once without considering the mentioned investment costs, and once including them. It is assumed that all ships are powered by hydrogen, while shore power and charge power are not taken into account in this particular example. Furthermore, as described in section 4.3, it is possible to incorporate initial values for hydrogen storage, electrolyser capacity, and transformer capacity ($H_{storage}^{startcap}$, $P_{ely}^{startcap}$, and $P_{trafo}^{startcap}$) in this model. However, these parameters are set to zero in this example to illustrate the costs associated with establishing a port, where non of the mentioned parameters exists to begin with.

Once more, this master thesis is an idealized study where the investment costs are handled as a one-time payment and are therefore weighted higher in the objective value than the annual operation costs. Nevertheless, it shows the impact of the investment cost and how due that the optimization algorithm is determining the dimensions of the components.

Figure 7.2 shows the production pattern of hydrogen (left) and the hydrogen storage and demand (right) for the system when the investment costs are not included (upper plots) and included (lower plots). In the case of no investment costs included, the model strives to produce all the required hydrogen in the cheapest hours of the year, because it has no limitations for the dimensions of the components. This is illustrated in the "Loads" plot, where it can be observed that the model only produces hydrogen in a few hours of the year. The highest power peak reaches 7340 MW, in some hours of May (between hours 2881 and 3624). At this time of the year, both the day-ahead price and peak price are normally low due to a lot of water in the hydro reserves from melted snow. Furthermore, this production pattern requires a hydrogen storage of 8056 tons, and a capacity of 7340 MW for both the electrolyser and transformer, which is not feasible. This is also illustrated in the hydrogen storage plot, where the storage only is filled mainly three times a year.

On the other hand, by considering the investment cost of the hydrogen storage, electrolyser capacity, and new transformer the production of hydrogen is spread more throughout the year as shown in the second "Loads" plot. The highest power peak is reduced to 169 MW, and the hydrogen storage is reduced to 216 tons. The electrolyser is, in this case, producing for above 4000 hours of the year.

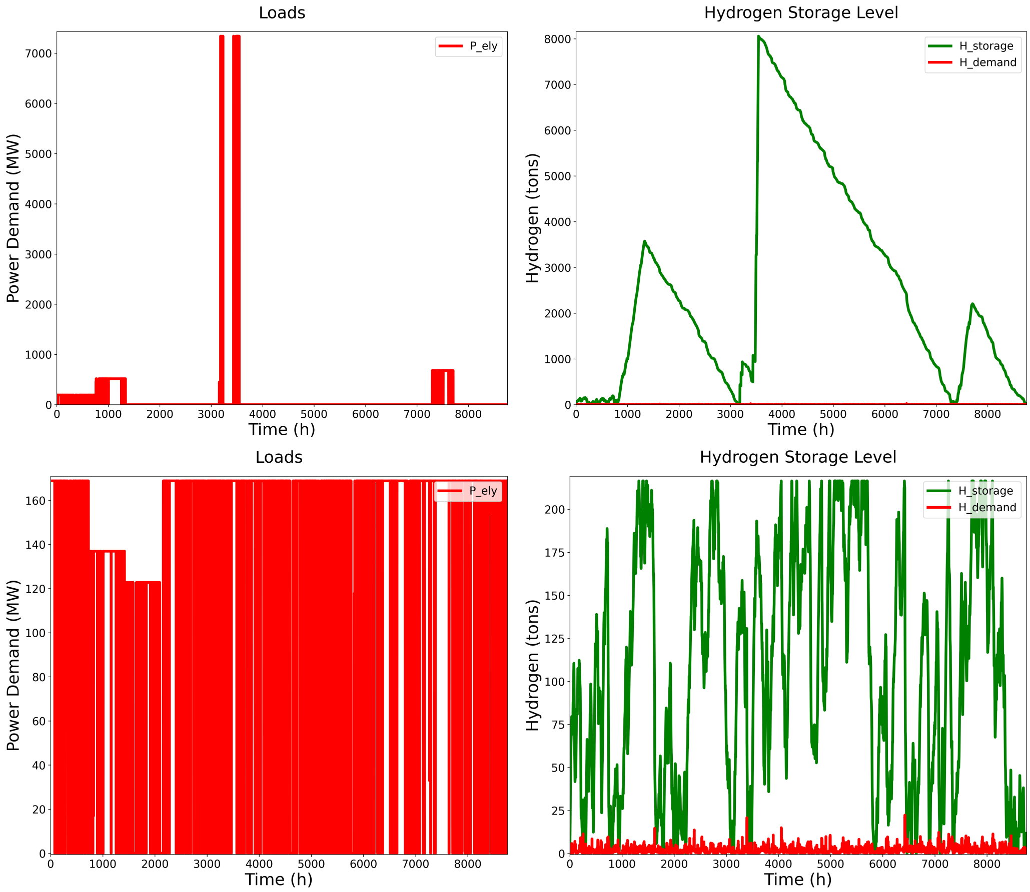


Figure 7.2: The plots to the left illustrate the production pattern of hydrogen given in MW, while the plots to the right show the hydrogen storage level and demand given in tons. The upper plots illustrate the results without investment costs, while the plots below present the results including investment costs.

Table 7.3 shows how the economic parameters $C_{storage}$, C_{ely} and C_{trafo} influence the system parameters and the power peaks. Naturally, the total energy demand stays the same, but the production pattern and therefore the power peaks differ. The reduction of power peaks decreases also the hydrogen storage size, electrolyser capacity, and transformer capacity. When the total investment costs are included, the annual operating expenses are twice as high. This is because the model is compelled to generate hydrogen during more expensive hours. Finally, there is a substantial disparity in the utilization time and the load factor when investment costs are taken into account compared to when they are not. These numbers confirm what is already evident from the load plots 7.2. With investment costs included, the electrolysis system would need to operate at a maximum capacity for 5479 hours to meet the total demand, whereas in the absence of investment costs, the utilization time is only 126 hours. When electrolysis, hydrogen storage, and transformer installations are implemented, it becomes financially advantageous to make full use of the capacity that has been invested in.

Table 7.3: Comparison of how the economic parameters influence the results of optimization problem

Description	With investment costs	Without investment cost
Objective value (MNOK)	3954	791
Total investment cost (MNOK)	2301	0
Annual operation cost (MNOK)	1653	791
Total energy demand (GWh)	925	925
Highest power peak (MW)	169	7340
Utilization time (h)	5479	126
Load factor (p.u)	0.63	0.01
Hydrogen storage (tons)	216	8056
Electrolysis capacity (MW)	169	7340
Transformer capacity (MW)	169	7340
Total hydrogen demand (tons/year)	18500	18500

7.2.2 Impact of installing PV production

This subsection illustrates the impact of installing solar power in the port of simulation. As described in section 2.4, solar power production depends on the location in Norway and the number of PV modules installed. In the following case, an installation of 15000 PV modules is assumed, whereas each PV module is 1.6 m^2 and has a power of 255 Wp [53]. This results for the port of Oslo in an installed power of 3.825 MW. The predicted number of PV modules is based on estimations made by [8]. They have considered that it will be room for all these solar panels on rooftops around the quay. In addition, as presented in section 6, the total area of all the seven quays is calculated to be 215 400 m^2. Installing 15000 PV modules will cover 11 % of the total area (24 000 m^2). Figure 7.3 presents the power produced each hour of the year considering 15000 PV models in area NO1. The production curve illustrates that there is more production during the summer hours than in the winter hours. The installed PV modules would produce in total 3831 MWh throughout the year with the highest power peak production slightly above 3 MW obtained in May (hour 3348).

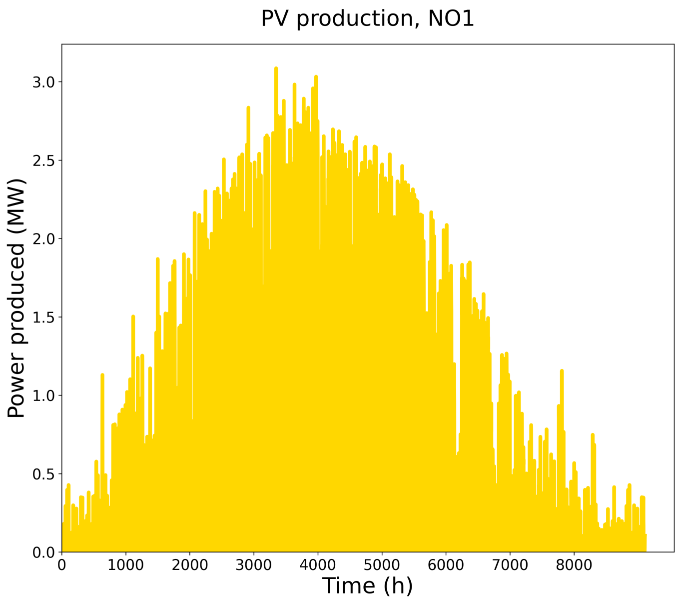


Figure 7.3: Produced power from 15000 PV modules installed in the port of Oslo (NO1)

To illustrate the influence of installing the 15000 solar panels in port, it is assumed that all ships in port are filled with hydrogen. All the outcomes are presented in Table 3 in the appendix F, and compared to the results from the previous section where PV is not included. The findings demonstrate that, in this particular case, solar power reduces the total energy purchased from the grid by 3831 MWh, which reduces the objective value by 7.4 million NOK. The size of the hydrogen storage is minimally increased, whereas the electrolyser is minimally reduced. These small changes do not affect the system, and the reduction in objective value is therefore mainly from the reduction in annual operation cost since the electricity produced from the solar panels is considered free of cost.

Figure 7.4 illustrate a scaled plot of the power balance, where the purple color shows the total power load, while the gold color represents how much electricity that is bought from the power grid. During the hours of solar production, the power purchased from the grid is reduced. This is illustrated best for February and March in the plot. In these months the highest peak of the month is reduced more than in the other months as presented in table 7.4. For the rest of the year, solar power reduces the annual production prices, but not as much as the high power peaks, as illustrated by the yellow covering the purple in most of the plot.

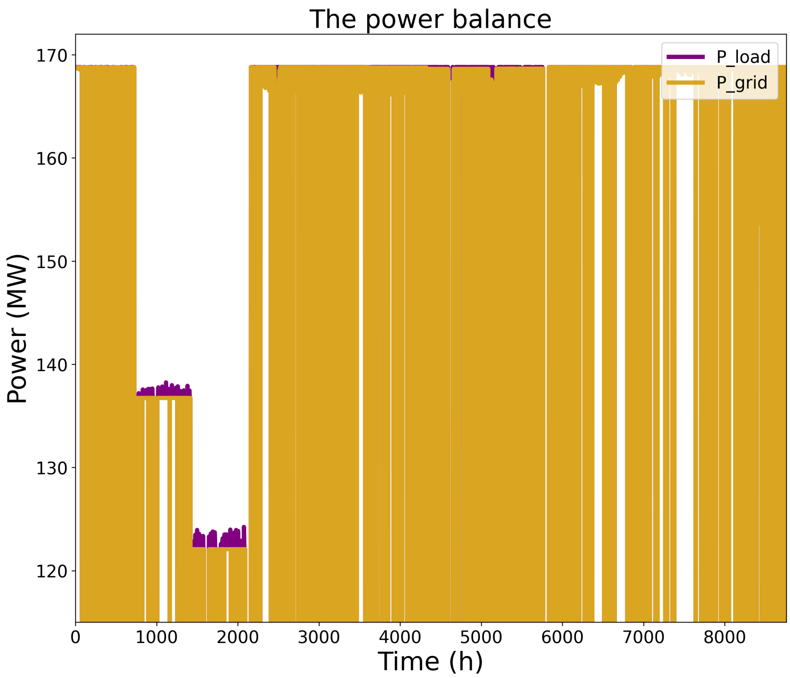


Figure 7.4: Scaled graph of the power balance when including PV

Table 7.4: Highest power peak every month of the year for the system with and without installation of PV modules

Highest power peak	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Without PV (MW)	168.82	136.95	122.77	168.82	168.82	168.82	168.82	168.82	168.82	168.82	168.82	168.82
With PV (MW)	168.78	136.74	122.07	168.81	168.80	168.77	168.64	168.66	168.81	168.81	168.81	168.81
Reduced peak (MW)	0.0387	0.2094	0.6961	0.0138	0.0149	0.0471	0.1803	0.1610	0.0053	0.0073	0.0068	0.0065

According to a cost analysis by [8], the investment cost of all the 15000 solar panels is 44.5 million NOK. Considering the savings of installing PV for the model of this master thesis illustrate that the PV modules could be paid down in approximately 6 years if the net present value is not considered. Moreover, this repayment period is related to the fact that the electricity prices in 2022 were really high.

7.3 Simulations of the fuel mix scenarios

This section aims to illustrate the impact of the fuel mix, by simulating five scenarios, presented in table 7.5, where all scenarios aim to give an overview of the predicted energy power and hydrogen demand, in addition to the optimal capacities of the hydrogen storage, electrolyser and transformer. The four first scenarios are named the "Extreme scenarios" since it considers that all ships in port are either powered by hydrogen, full electric, plug-in hybrid, or connected to shore power (section 5.2). The fifth scenario is named "Zero emission mix" and considers a mix of hydrogen, full-electric and shore power. The results of all scenarios are presented as duration curves before the numbers are presented in a comparison table 7.6 at the end.

Table 7.5: Overview of the fuel mix of each of the five scenarios

Name:	**Extreme scenarios**				**Zero emission mix**
Scenario number:	**1**	**2**	**3**	**4**	**5**
Fuel:	Hydrogen	Full-electric	Plug-in electric	Shore power	Full-electric: Size category 1 and 2 Hydrogen: Size category 3 and bigger Shore power: All ships segments

The different fuel mixes are used as input data in "Opinv", together with the other input data listed in 5.4. Furthermore, the previously discussed impacts (investment costs and the number of PV modules) are included in the simulation model. In addition, a hydrogen storage start and end level H_{level}^{start}, H_{level}^{end} are included. This is mainly included to avoid the high power peaks at the beginning of the year when the model strives to produce all the hydrogen for the first ships. Secondly, the end value is included to achieve that the result presents the right amount of hydrogen produced in the model. For this simulation, a hydrogen storage start and end value are equal to the highest hydrogen demand in an hour of the year. This value is not set higher because the end optimal hydrogen storage size is not found yet. The start and end values will further be discussed in the sensitivity analysis 8.4.

Scenario 5 aims to show the outcome if all arriving ships at the port of Oslo are filled with green fuel. It is assumed that the two smallest ships' size categories are powered by batteries as full-electric ships, while the ships from categories three and bigger are using hydrogen. This scenario is based on the discussion from section 3, where the biggest ship categories most likely will be fueled with hydrogen or hydrogen carriers such as ammonia and methanol. Since the efficiencies of ammonia and methanol are not included, the results in this scenario present the minimum energy and power demand if all ships are green.

Comparison of the five fuel mix scenarios

Figure 7.5 shows the duration curves for the port of Oslo if all arriving ships either would have needed shore power, charge power to full-electric vessels, charge power to plug-in electric vessels, or power to produce hydrogen to cover the demand for hydrogen ships.

The load duration curve for hydrogen (upper left) in figure 7.5 is a plot that displays clear steps, which can be explained by observing the production pattern depicted in the previous figure 7.2. In order to minimize the peak price per month, the model attempts to reduce the peak every month. However, if the demand results in a high peak in a particular month, the model strives to produce more hours at this peak to maximize utilization. Therefore, the model produces hydrogen at its maximum capacity (169 MW) for almost 4800 hours. Since the model also aims to produce hydrogen in the cheapest hours within all the months, it results in zero production for certain hours. In this specific scenario, the production of hydrogen is equal to zero for approximately 2250 hours. The total hydrogen demand, in this scenario, is 18500 tons, where the maximum hydrogen demand in one hour is 22.3 tons.

The load duration curve for shore power, the upper left plot in figure 7.5, shows a permanent decreasing curve with the highest peak equal to 3 MW. This peak appears for just a few hours during the year. In 90 % of the year, the power demand remains lower than 1.5 MW. Unlike the load duration curve for hydrogen production, the power demand, in this scenario, appears at all hours of the year, indicating that there is always a ship in port.

In the scenario of full-electric ships, the highest power peak reached 411 MW, as shown down to the left in figure 7.5. However, in approximately 95 % of the year, the power peaks remained under 100 MW. This demonstrates that the occurrence of high-power peaks is infrequent. The high power peaks may be attributed to the simultaneous arrival of several large ships with high energy demands at the port. Therefore, optimizing the logistics in the port could effectively mitigate such high peaks. Furthermore, it has not been implemented any battery at the port for this simulation, which leads to the power demand needing to be covered straight from the power grid. Implementing a battery at the port can probably reduces the high power peaks.

The load duration curve for the plug-in hybrids, shown down to the right in figure 7.5, follows the same shape as for the full-electric ships but has naturally a reduced power peak. In this scenario, the highest power peak is 38 MW. However, most of the hours during the year have a power demand under 5 MW.

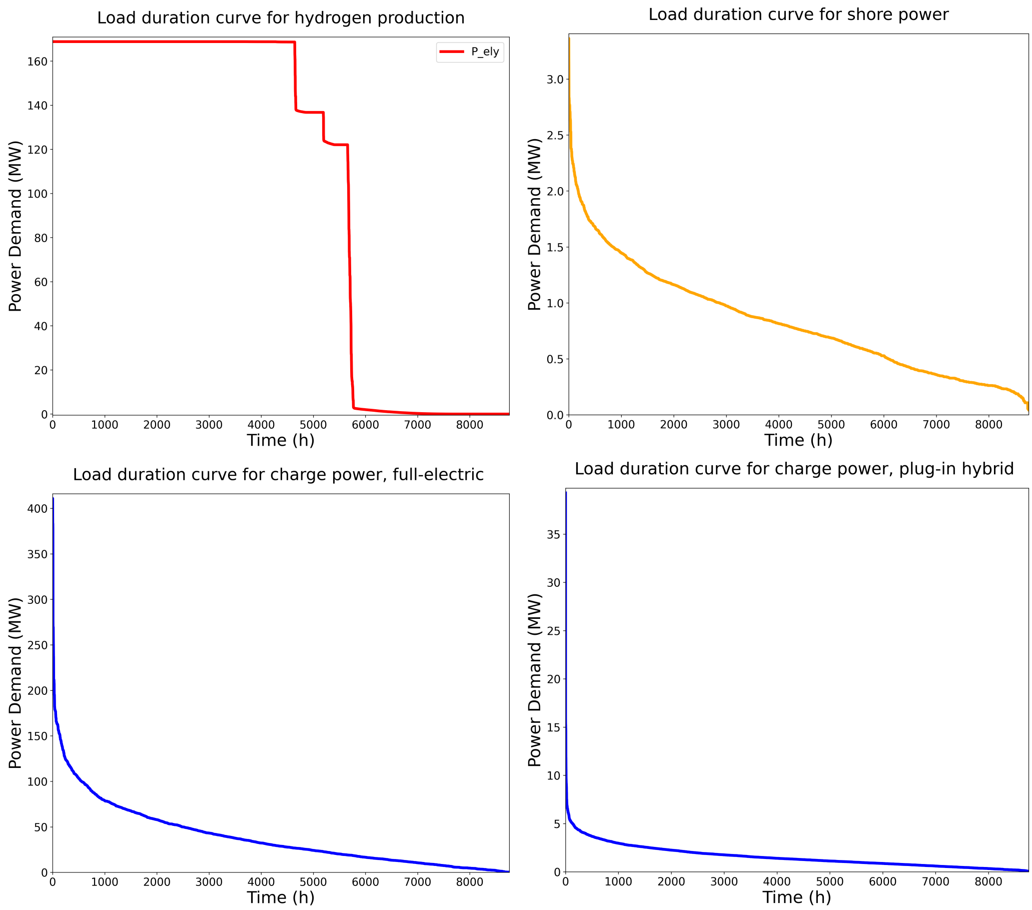


Figure 7.5: Duration curves for the extreme scenarios; hydrogen, shore power, full-electric and plug-in electric.

Figure 7.6 shows the duration and production curve for Scenario 5 which considers the total load in the port of Oslo, including the mix of shore power, the charge power, and the production of hydrogen. The highest power peak of 171 MW is reached in only a few hours of the year, which can be observed in both the duration and production plot in figure 7.6. Interestingly, the power demand for full-electric ships causes the highest power peaks in the system, while the power demand for the production of hydrogen remains below 120 MW. The duration curve illustrates that the load in total is below 140 MW in 90 % of the year.

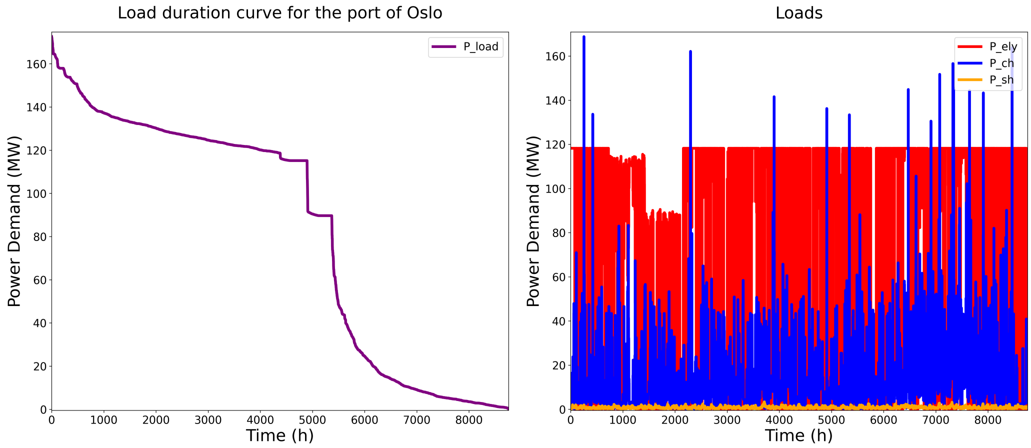


Figure 7.6: Duration and production curve for the port of Oslo considering scenario 5

The summary of the total energy demand, highest power peak, utilization, and load factor for the four different scenarios are presented in table 7.6.

Table 7.6: Results from the five fuel mix scenarios

Scenario number:	**1**	**2**	**3**	**4**	**5**
Scenario name	**Hydrogen**	**Full electric**	**Plug-In hybrid**	**Shore Power**	**Zero emission mix**
Total energy demand (GWh)	924	342	14	7	728
Total energy demand for hydrogen production (GWh)	924	0	0	0	601
Total energy demand for charge power (GWh)	0	342	14	0	120
Total energy demand for shore power (GWh)	0	0	0	7	7
Highest power peak (MW)	169	411	38	3	171
Utilization time (h)	5472	832	364	2499	4263
Load factor (p.u)	0.62	0.09	0.04	0.29	0.49
Hydrogen storage (tons)	216	0	0	0	222
Electrolysis capacity (MW)	169	0	0	0	118
Transformer capacity (MW)	169	411	38	3	171
Total energy bought from the power grid (GWh):	920	338	11	5	724
Total energy produced by PV (GWh)	4	4	4	4	4
Total hydrogen demand (tons)	18500	0	0	0	12040
Maximum hydrogen demand in one hour (tons)	22	0	0	0	21

It is evident that if all ships were fueled with hydrogen, the total energy demand would have been 924 GWh, which is 2.7 times greater than if all ships were full-electric. However, hydrogen production is flexible, as evidenced by the fact that its highest power peak reached 169 MW, while the highest power peak for full-electric ships was over twice as large at 411 MW. Additionally, hydrogen production has a higher utilization and load factor, with a utilization of the electrolyser of 5472 hours, meaning that the facility would operate at maximum power for 5472 hours to meet the total demand. When investing heavily in capacities, the objective is to utilize them as much as possible. In Scenario 2 and 3, with the full-electric and plug-in hybrid, the utilization of the transformer and load factors are small. This can also be observed in the graph where the highest power peak is way higher than the rest of the power demand throughout the year. This indicates that it is only in a few hours of the year that the port experience high peaks. Furthermore, the energy demand for shore power is the lowest, equal to 7 GWh, with the highest power peak of 3 MW. In this special case, the port did not utilize all the power from the solar panels to cover the shore power demand due to a mismatch in time between the demand and production. For plug-in hybrids an energy demand of 14 GWh is required, with the highest power peak of 38 MW.

Scenario 5 obtained a total energy demand of 728 GWh, which is smaller than Scenario 1 where only hydrogen is considered. This illustrates once more the efficiency of hydrogen production and usage, where a lot of energy is lost in the process. Furthermore, between Scenario 1 and 5, the electrolyser capacity is reduced by 51 MW, while the hydrogen storage and transformer are slightly increased by 6 tons and 2 MW, respectively. The increase in transformer capacity is necessary to handle the charge demand in Scenario 5, compared to Scenario 1 where the transformer is equal to the capacity of the electrolyser. Moreover, the total hydrogen demand is reduced by 6460 tons by implementing full-electric instead of hydrogen for the first two size categories. The maximum hydrogen demand in one hour is reduced by 1 ton, indicating that one ship in this exact hour is full-electric instead.

Continuing, table 7.7 presents the objective value given in million NOK for all the scenarios. The objective value is also split up and presented as the annual operation and total investment cost. As expected, the costs correspond to the total energy demand, with shore power (Scenario 4) being the most economical option, while hydrogen (Scenario 1) is the most expensive. In scenarios where no hydrogen is considered (Scenarios 2, 3, and 4), the operational costs are approximately 8, 3, and 11 times higher than the investment costs. Conversely, in scenarios involving hydrogen (Scenarios 1 and 5), the investment costs outweigh the operational costs. This difference is caused by the fact that in the scenarios including the investment costs for hydrogen storage and electrolyser in addition to the transformer are included. As presented earlier, the investment costs for electrolyser and hydrogen storage are way more expensive than the transformer in this study.

Table 7.7: Objective value (annual operation and total investment cost) for the five different fuel mix sceanrios

Scenario number:	**1**	**2**	**3**	**4**	**5**
Description	**Hydrogen**	**Full electric**	**Plug-In hybrid**	**Shore Power**	**Zero emission mix**
Objective value (MNOK)	3945	876	36	11	3318
Total investment cost (MNOK)	2301	99	9	1	2010
Annual operation cost (MNOK)	1644	778	27	11	1308

7.4 Steps to the future

In this section, a simulation for one scenario, consisting of three assumed steps into the zero-emission future of the maritime sector named "Steps to the Future", is investigated. Figure 7.7 illustrates the fuel mix in each of the three "Steps to the Future".

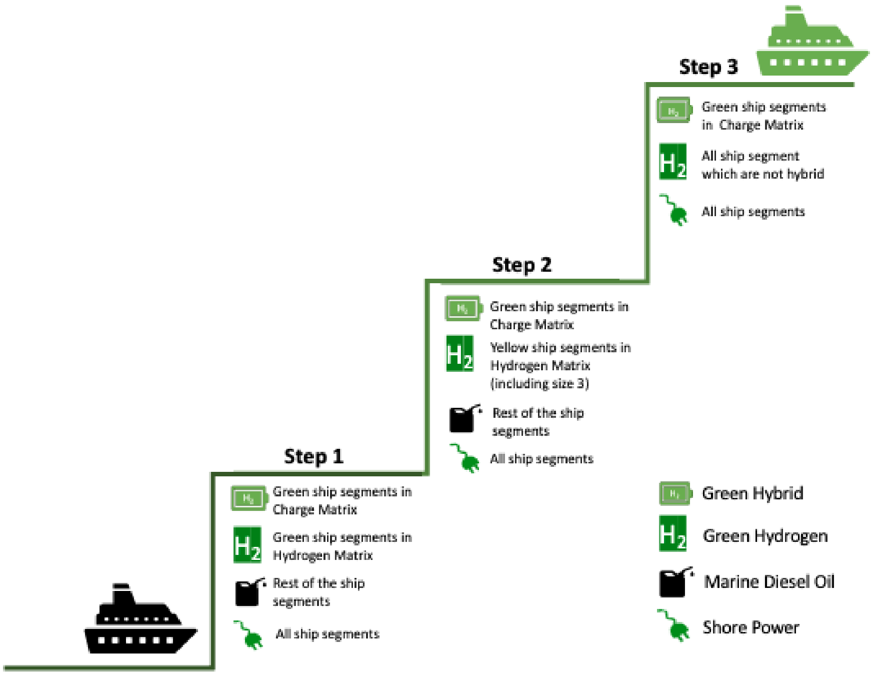


Figure 7.7: Steps to the future of a zero-emission maritime sector. The Hydrogen Matrix and Charge Matrix are presented in table 5.2 and 5.4

This simulation includes the same parameters and input data as mentioned in section 7.3. However, it is important to note that the "Steps to the Future" focuses even more on the characteristics of the port of Oslo. Therefore, in this context, the initial value of the transformer capacity, P^{start}_{trafo}, is set to the existing total capacity of 36.715 MW, which is currently available at the port, as presented in the chapter 6. Moreover, since electrolyser and hydrogen storage are not implemented yet at the port, their start values are set to zero. For each new step, the capacities obtained in the previous step will serve as the start capacities. This approach ensures that the optimization model builds upon the capacities and infrastructure already established in earlier stages, allowing for an iterative analysis of the system's performance and optimization.

The fuel mix of the steps is based on the discussion in chapter 3, where the main conclusion was that small ships that have a predicted route between ports will use batteries while the rest will need hydrogen or hydrogen-based fuels such as ammonia and methanol. Since the routes of the ships in the port log of Oslo is unknown the general assumption of which ships segments are full-electric or plug-in hybrid is based on table 5.4. The remaining energy demand of a ship after implementing plug-in hybrid are covered by hydrogen-based fuels achieving a zero-emission ship. The term "Green Hybrid" is introduced in this master thesis as a ship that is powered by both battery and hydrogen as presented in section 2.1.3. Table 5.2 and 5.4 are used to make the "Green Hybrid" alternative. Based on the current situation, the implementation of shore power is assumed to happen in close future and is therefore considered from the first step to the last step.

Step 1, consider what is most likely to first be implemented for the different ship segments based on the green squares presented in tables 5.4. The percentage in the table shows how much of the total energy demand the ship can be powered by a battery. The rest of the energy demand is covered by hydrogen. Furthermore, Step 1 includes hydrogen for the rest of the green squares in the hydrogen table 5.2, which are not utilized for "Green hybrid". The first step mainly considers the first size category and half of the second size category. In step 2, it is assumed that the technology of the green fuels is improved, and therefore the rest of size categories 2 and 3, are covered by hydrogen, except the squares in table 5.2 colored in red. The rest of the size categories will still be covered by fossil fuel as in use today. The final step extends the previous steps by fueling all the missing ship segments with hydrogen. Again, for simplification reasons, hydrogen represents the fuels pure hydrogen, methanol and ammonia in this simulation. Since methanol and ammonia have lower efficiency rates, the expected energy demand will probably be even higher than what is presented. The input matrices for Step 1 are presented in appendix G and H.

7.4.1 Results of the "Steps to the Future" scenario

First of all, Table 7.8 presents the total hydrogen demand for the different steps. The hydrogen demand increases by 97 % from the first to the last step, from 9248 tons to 18260 tons. Between Step 1 and Step 2, the total hydrogen demand increased by 36 % while the maximum hydrogen demand for an hour remains almost the same.

Table 7.8: Total hydrogen demand and the maximum hydrogen demand in one hour for all the steps

	Step 1	**Step 2**	**Step 3**
Total hydrogen demand (ton/year)	9248	12598	18260
Maximum hydrogen demand in one hour (ton)	10.4	10.7	22.3

Figure 7.8 shows how the electric energy demand in the port will increase over time, in three steps. The total energy demand starts at 473 GWh for Step 1 and will reach 923 GWh in Step 3. The energy demand for shore power and charge power is equal to 7 GWh and 4 GWh, respectively, and will stay the same through the three steps. Therefore, the power demand for hydrogen production is the only load that differs in the steps.

The total energy demand increases by 35% from Step 1 to 2, and 44% from Step 2 to 3. In Step 3, more hydrogen is used to fuel ships compared to the previous steps, which is why the total energy demand is higher. As shown in figure 7.8, the annual operation cost for the port also increases correspondingly to the total energy demand in each step.

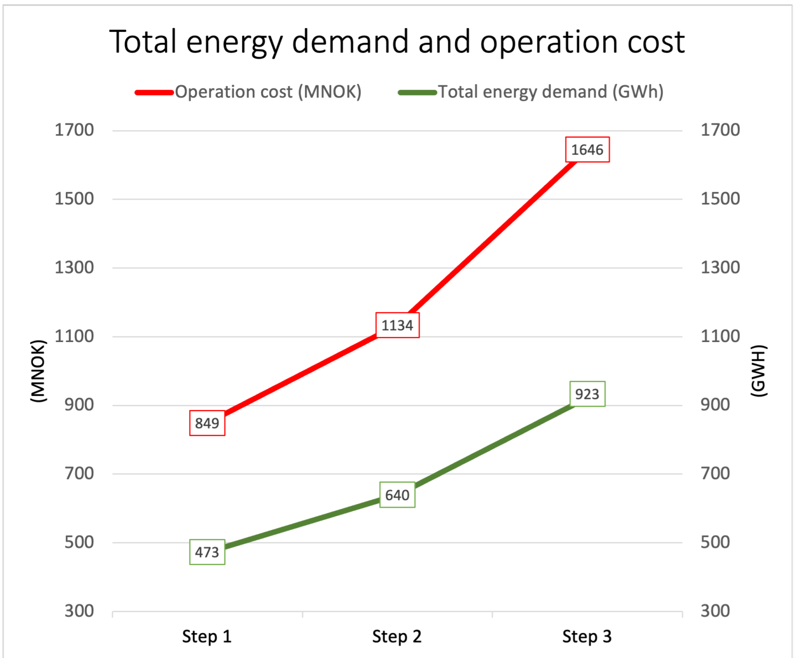


Figure 7.8: Total energy demand in the port of Oslo given in GWh and the operation cost is given in million NOK

Figure 7.9 presents the total capacities of electrolyser, transformer, and hydrogen storage for each step of the analysis. Notably, all of these capacities exhibit an overall increase as the steps progress. However, it can be observed that the growth rates differ between the steps. The electrolyser and transformer capacities have a steeper increase from Step 1 to Step 2, with 50% than between Steps 2 and 3 which only increase with 8 %. In contrast, the hydrogen storage starts at a low capacity of 36 tons in Step 1 and increases by 44 % to Step 2. Between Step 2 and Step 3, the growth rate accelerates significantly reaching an increase of 317% and total storage of 217 tons. As the total hydrogen demand increases, the need for bigger storage or electrolyser capacity is necessary. The investment costs of electrolyser and transformer capacity are higher than the hydrogen storage price. Therefore, the huge increase in hydrogen storage is computed so the system can handle the increased hydrogen demand as cheaply as possible.

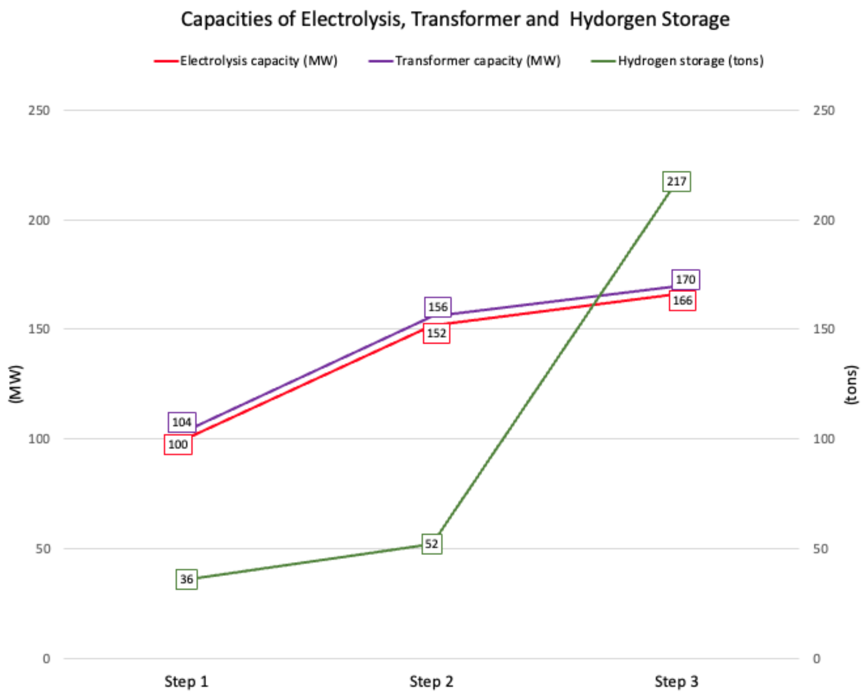


Figure 7.9: Capacities of the electrolysis, transformer and hydrogen storage in each of the three "Steps to the Future"

Table 7.9 presents the investments cost for the electrolyser, transformer, and hydrogen storage for each step and the total investment cost for the simulation. The highest total investment cost of the system is the investment in hydrogen storage, while the transformer has the lowest total investment cost. The investment in electrolyser is biggest for Step 1, with 641 MNOK, while the investment cost is a smaller amount for the rest of the steps. The hydrogen storage is causing 90 % of the total investment cost for Step 3. This corresponds to the extreme increase in the hydrogen storage capacity chosen in this step.

Table 7.9: Total investment costs for the three steps

Investment costs (MNOK)	**Step 1**	**Step 2**	**Step 3**	**TOTAL**
Hydrogen storage	196	87	902	1185
Electrolysis	641	331	91	1064
Transformer	16	12	3	32
TOTAL	853	431	997	2281

The load duration curves for hydrogen production are presented in figure 7.10 and illustrate the highest power peak and how much time of the year this peak occurs. Furthermore, it shows how many hours of the year the electrolyser produces hydrogen. Step 1 produces hydrogen at max capacity (104 MW) for approximately 3500 hours of the year. For the rest of the production time, the power peaks are mainly between 90 and 70 MW. Step 2 reaches a higher power peak equal to 147 MW. The electrolysis has produced hydrogen at this level for approximately 3000 hours. It mainly produces at capacities between 110 and 90 MW for the remaining production time of 200 hours. Step 3 shows a greater energy demand with the highest power demand of 170 for approximately 4800 hours of the year. In the remaining hours, the capacities are mainly between 140 MW and 120 MW. All the steps show that the model produces some demands below 5 MW for approximately 500 hours of the year.

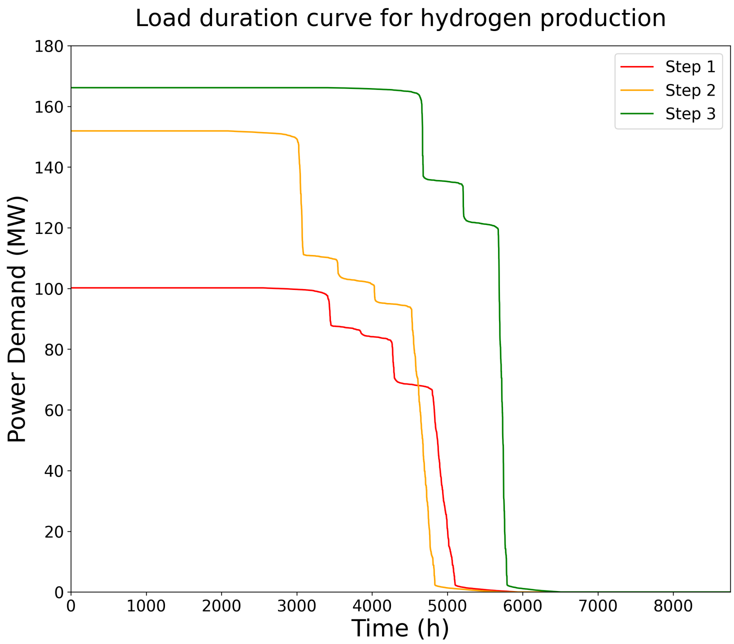
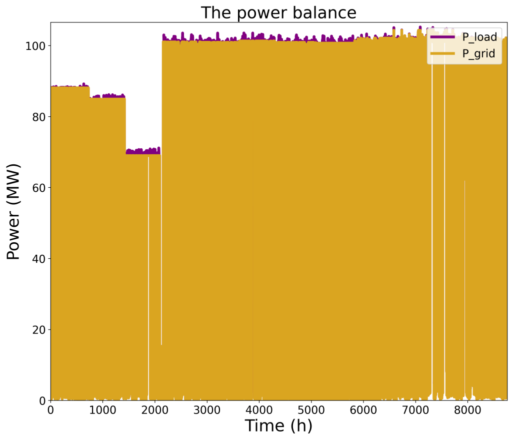


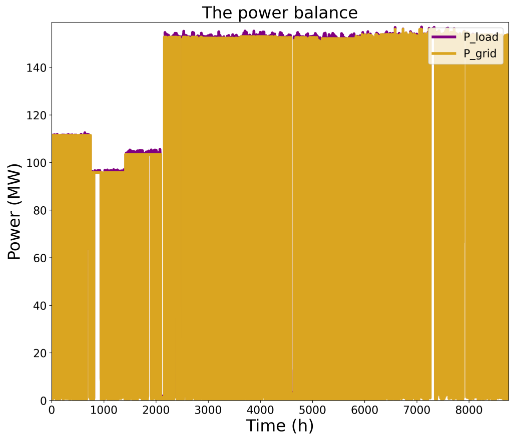
Figure 7.10: Load duration curve for hydrogen production for each of the three steps

The power balance for the three different steps are presented in the following plots in figure 7.11. It can be observed that the power purchase pattern for Step 1 and Step 2 is similar, as they both exhibit lower power consumption during the initial three months followed by a stable high peak demand for the rest of the year. Step 3, on the other hand, has a slightly different production pattern with a high peak in January before the peak is reduced for two months and then raised again to a high peak throughout the year. The model aims to minimize costs as long as the demand is fulfilled. Consequently, it focuses on reducing the peaks during the winter months due to the higher prices associated with power peaks during this period. Therefore, the high peaks observed in January for Step 3 indicate a significant demand for hydrogen during this time. The same reasoning applies to the other winter months (October, November and December).

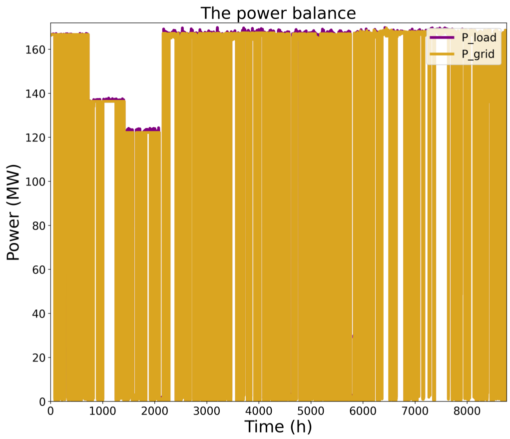
Furthermore, the white areas in the plots illustrate power production at the same power level over several hours. This phenom occurs slightly for Step 3, while almost not at all for Step 1 and Step 2. This indicates that the power bought from the grid switching on and off between the cheaper and more expensive hours of the day.



Step 1



Step 2



Step 3

Figure 7.11: Power balance for Step 1, Step 2 and Step 3

7.4.2 Analysis of results

The "Steps to the Future" analysis reveals differences between Step 1, Step 2, and Step 3 for all parameters. Most interesting are the total energy demand, power demand, hydrogen demand and costs. The most economical alternative is naturally to only introduce Step 1. However, it would not fulfill the objective of achieving a zero-emission maritime sector. Step 2 is more expensive than Step 1, but not as expensive as Step 3. Therefore, an analysis has been made of what happened between these two last steps.

Within Step 3, it has been identified that 149 ships cause a huge increase in total investment costs, annual operational costs and energy demand. These vessels primarily belong to ship segments 4 or 5, ranging in size from 25 613 GT to 29 874 GT. The ship types are Chemical/product tankers, car carriers combined carriers, general cargo, and Oil tankers. Among these, the oil tanker category plays a dominant role in driving the overall increase, primarily due to its large hydrogen requirements. Consequently, it may be worth exploring alternative fuels for such ship types that do not rely on electricity. One potential alternative could be biofuel but that is not further investigated.

7.4.3 CO2 emission

Based on the results of the "Steps to the Future" a simplified reduction in CO2 emission was calculated. The calculation method and assumptions are presented in the appendix K.

Implementing shore power for all the ships in the port of Oslo in 2018 would result in a reduction of 4505 tons of CO2 per year. Furthermore, the emission of the required charge demand for all three steps is calculated to be 2574 tons of CO2 per year. The reduced CO2 emission per step is presented in table 7.10, where Step 3 represents a 100 % reduction.

Table 7.10: CO2 reduction per step

	Step 1	**Step 2**	**Step 3**
Total hydrogen demand (ton/year)	9248	12598	18260
Reduced CO2 emission per year (ton/year)	109103	148625	215422
Total energy demand for shore power (GWh/year)	7	7	7
Total reduction in CO2 emission per year (ton/year)	4505	4505	4505
Total energy demand for charge power (GWh/year)	4	4	4
Total reduction in CO2 emission per year (ton/year)	2574	2574	2574

7.4.4 Comparison of all the scenarios considering hydrogen as fuel

This subsection treats Step 3 as an independent scenario, facilitating a more straightforward comparison with the two other zero-emission scenarios that involve hydrogen (Scenario 1 and 5 from section 7.3). In this simulation, the only modification made for Step 3 is the start values of the transformer, hydrogen storage, and electrolyser are set to zero. The result of considering Step 3 as an independent scenario did not change any of the system parameters or results, except the total investment costs. The total investment cost increased because the start capacity of the transformer equal to 36715 MW was excluded.

Table 7.11 presents the findings obtained from Scenario 1, Scenario 5, and Step 3. Notably, there is a marginal difference between the scenario where all ships are powered by hydrogen (Scenario 1) and where some ships are considered Green Hybrid ships (Step 3). Additionally, if a greater number of fully electric ships is included, as demonstrated in Scenario 5, the total energy demand approximately is reduced by 200 GWh. However, due to the significant peaks of 170 MW, the grid infrastructure dimensions would remain the same as in the other two scenarios.

From the annual operation cost perspective, Scenario 5 is the most economical scenario. However, considering the discussion presented in chapter 3, the implementation of full-electric ships for all the ships in the two first size categories are still considered challenging and most unlikely. Conversely, by maximizing the power capacity on the ships, as demonstrated in Step 3, by utilizing Green Hybrid, the objective value is reduced compared to Scenario 1, where all ships rely solely on hydrogen as their fuel source.

Table 7.11: Comparison of Scenario 1 (Hydrogen), Scenario 5 (Zero emission mix) and Step 3

Description	**Hydrogen**	**Zero emission mix**	**Step 3**
Objective value (MNOK)	3945	3318	3935
Total investment cost (MNOK)	2301	2010	2290
Annual operation cost (MNOK)	1644	1308	1646
Total energy demand (GWh)	924	728	923
Total energy demand for hydrogen production (GWh)	924	601	912
Total energy demand for charge power (GWh)	0	120	3,9
Total energy demand for shore power (GWh)	0	7	7
Highest power peak (MW)	169	171	170
Hydrogen storage (tons)	216	222	217
Electrolysis capacity (MW)	169	118	166
Transformer capacity (MW)	169	171	170
Total hydrogen demand (tons)	18500	12040	18260
Maximum hydrogen demand in one hour (tons)	22	21	22

Chapter 8

Sensitivity Analysis

To explore the impact of various system parameters and input values in the developed models, sensitivity analyses are conducted. The sensitivity analyses rely on the input data used in Step 3, which includes the combination of fuels (hydrogen and green hybrid), the use of shore power, and 15000 installed PV modules. In addition, for simplification and clarity Step 3 is considered as an independent scenario implemented in a port with zero start values for the transformer capacity, hydrogen storage, and electrolysis capacity. In other words, the start value of the transformer equal to 36715 MW is not included in the sensitivity analysis.

Each change made to the system parameters is explained in its own section, with the following results and comparisons. The results are compared to Step 3 considered as its independent scenario. The following parameters and input data are investigated:

- Investment cost:
  - → Hydrogen storage (NOK/kg): C_{storage}
  - → Electrolyser (NOK/kW): C_{ely}
  - → Transformer (NOK/kW): C_{trafo}
- Day-ahead prices
- The port log
- The start value of the hydrogen storage
- Peak shaving

8.1 Investment cost

The investment costs for the electrolysis, transformer, and hydrogen storage, used in the simulation are unsure parameters with a wide spread as presented in section 2.5. Therefore, it is investigated how different prices would affect the results. Based on the prices presented in section 2.5 it is chosen to evaluate the impact of a 50 % higher and lower cost than presented. The new prices are still in the range of the numbers presented and discussed. The tested total investment costs are presented below.

- **Investment cost**
  - → $C_{\text{ely}} = 6400$ NOK/kW $\pm$ 3200 NOK/kW
  - → $C_{\text{hstorage}} = 5450$ NOK/kg $\pm$ 2725 NOK/kg
  - → $C_{\text{trafo}} = 240$ NOK/kW $\pm$ 120 NOK/kW

Figure 8.1 depicts how the system's objective value is affected by varying the investment costs of the electrolysis, hydrogen storage and transformer. The analysis is conducted by testing one investment cost change at a time, with the original costs of the two other components kept constant. For instance, if the electrolysis cost is increased by 50%, the hydrogen storage and transformation price are kept at the original price. The results presented in figure 8.1 show that the highest objective value is attained when the investment cost for hydrogen storage is increased by 50% while keeping the costs of electrolysis and transformer at their original values. A slightly lower objective value is attained by increasing the investment cost for electrolysis by 50%. Both scenarios result in an objective value that is above 480 MNOK higher than the original problem, shown in the middle of the figure. However, reducing the investment costs for both hydrogen storage and electrolysis by 50%, each in turn, leads to a reduction of the objective values by more than 630 MNOK. The investment cost for the transformer has a smaller impact on the results as the investment cost already is way cheaper than the investment cost for electrolysis and hydrogen storage. However, the objective value is changed by approximately 20 MNOK depending on the increase or reduction of the transformer's investment cost.

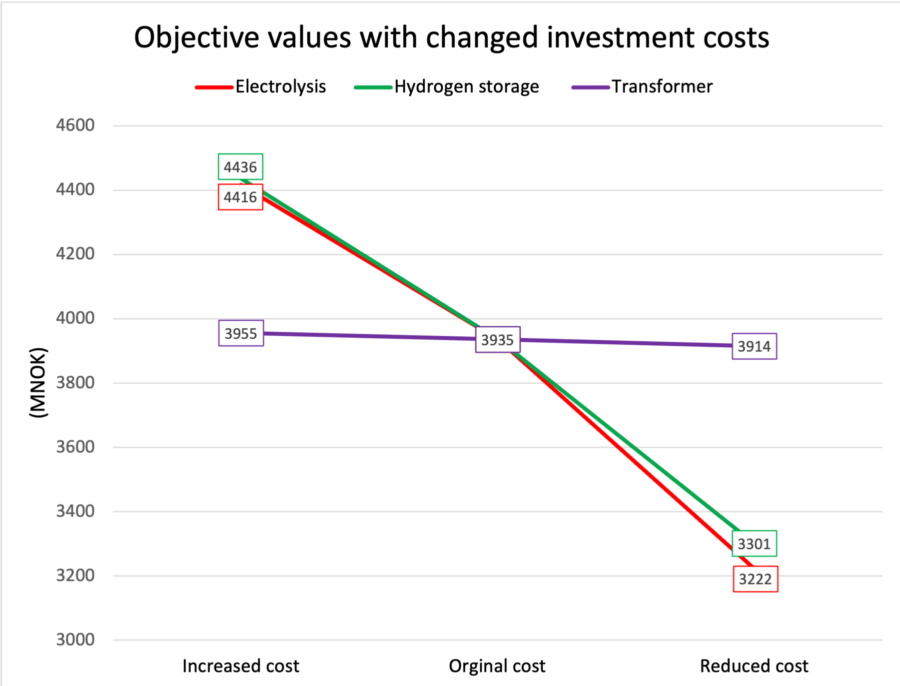


Figure 8.1: Objective value with different investment costs of the electrolysis, hydrogen storage and transformer

Figure 8.2 illustrates how the hydrogen storage size and electrolysis/transformer capacity change for the different investment costs. The lowest hydrogen storage, 112 tons, is reached in the case where the electrolysis price is lower than in the original problem. In the same case, the electrolysis and transformer have the highest capacities, equal to 290 MW and 294 MW, respectively. As presented in figure 8.1, the lowest total investment cost was also reached for this case. With a smaller hydrogen storage, the model is forced to produce more hydrogen in certain hours, which correlates to the high electrolysis capacity. In the two cases where either the investment cost of the electrolysis increase or the hydrogen storage price is reduced, the same sizes of increased hydrogen storage (237 MW) and a reduced electrolysis and transformer capacity (147 MW and 151 MW), are obtained. The increased investment cost of hydrogen storage naturally reduces the hydrogen storage, but not as much as if the investment cost of the electrolysis is reduced. The change in the investment cost for the transformer reduces or increases the sizes by approximately 4 to 5 tons or MW. As the investment cost of the transformer is increased the capacities for electrolysis and transformer are slightly reduced, while the hydrogen storage is slightly increased. More of the results are presented in appendix L.

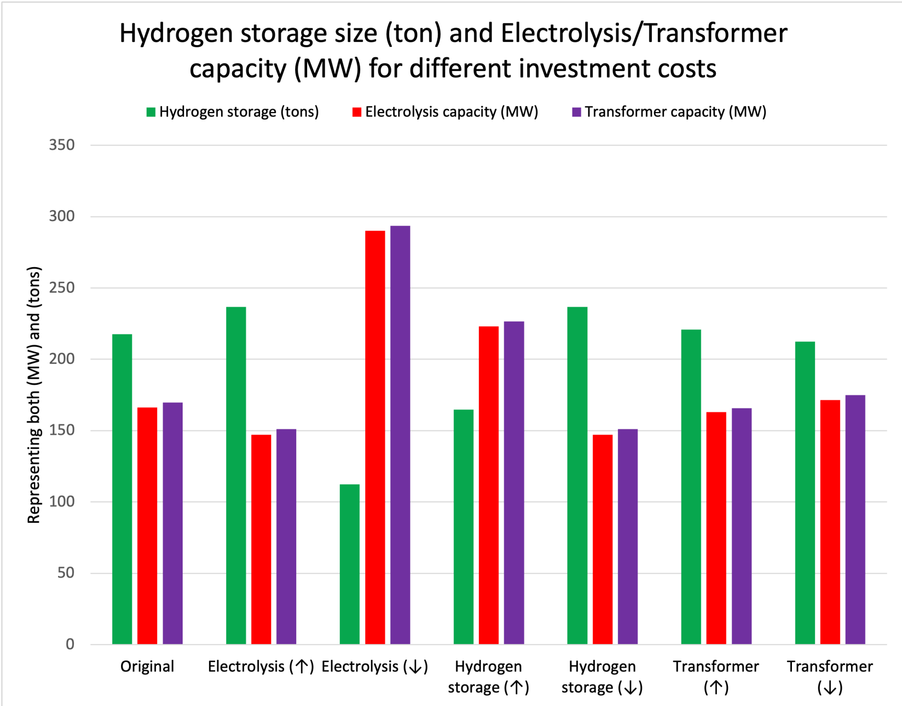


Figure 8.2: Hydrogen storage size and electrolysis/transformer capacity for the different investment costs. The arrow represents if the investment cost for the mentioned parameter was 50 % higher or lower than the original value.

8.2 Day-ahead prices

Figure 8.3 illustrates how the objective value, investment and operation costs of the model change depending on the year of the day-ahead prices. As presented in 2.2.6, electricity prices have changed a lot in the last five years. The resulting objective values follow the same trends as the day-ahead prices. Meaning that the objective value is lowest in 2020, where also the electricity price was lower than ever. The objective value for the years 2018 and 2019 are similar, while it increases in 2021 and 2022. The graphs show a difference of 1497 MNOK between the highest and lowest objective value. The investment cost stay constant at 2267 MNOK for the first four years before it increased to 2290 MONK in 2022. This indicates that some of the system parameters had to increase this year to minimize the total price. The electrolysis and transformer capacity increased from 147 MW and 151 MW to 166 MW and 170 MW, respectively. The hydrogen storage on the other hand is reduced from 237 tons to 217 tons.

Following, the annual operation cost varies extremely in the simulation with different day-ahead prices, with a variation ranging from 172 MNOK in 2020 to a maximum cost of 1646 MNOK in 2022. This indicates an increase of 856 %. Compared to the day-ahead prices from a "normal" year represented by 2018, the increase amounts to 259 %. This analysis highlight the uncertainty and difficulty associated with conducting cost analysis based solely on electricity prices in the current and future times.

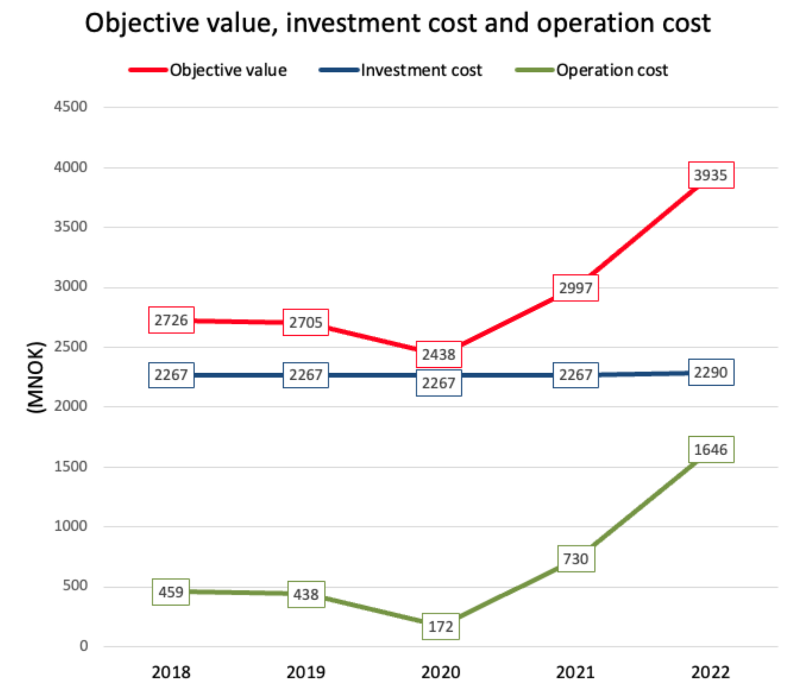
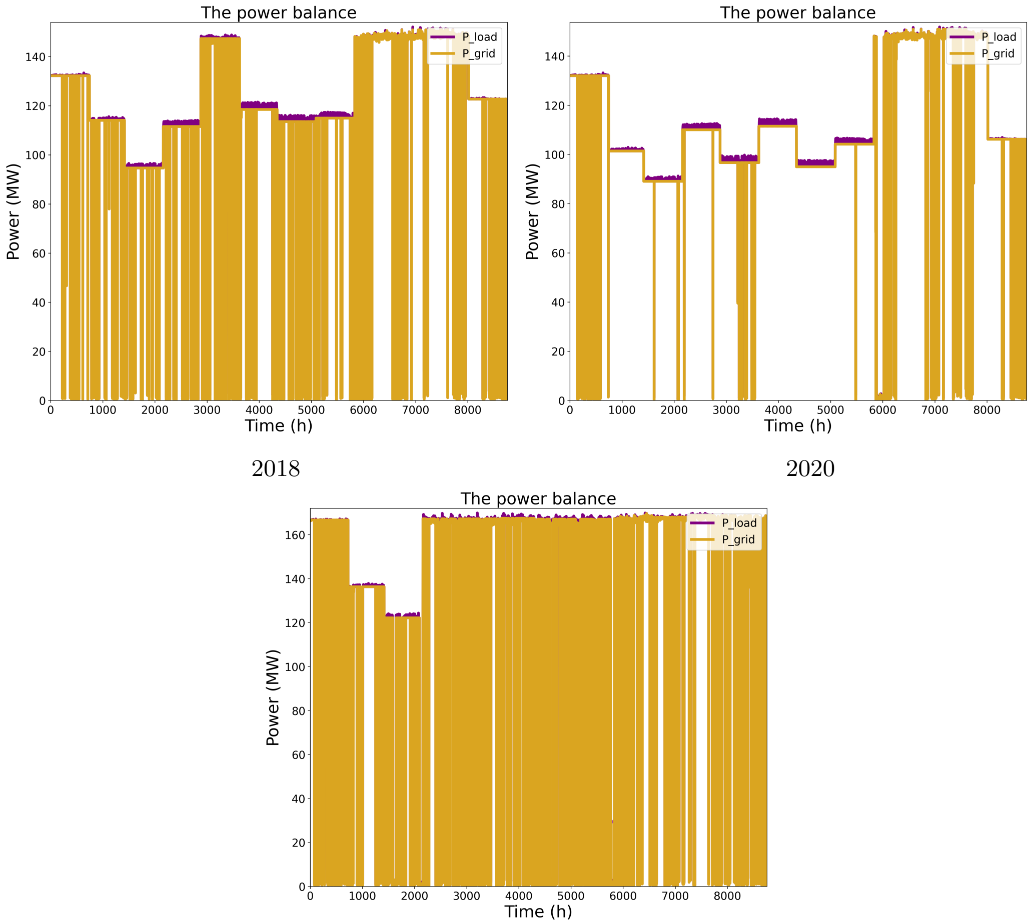


Figure 8.3: The objective value, total investment cost and annual operation cost when different day-ahead prices are considered

In the simulation, the dimension of the components are only different in 2022 while it remains the same for the previous years as presented in appendix M. Nevertheless, the production pattern for hydrogen varies for each year under consideration. It is chosen to present the power balance (figure 8.4) and the load duration curve for hydrogen production (figure 8.5) for the three years, 2018, 2020, and 2022. These years were selected to represent a historically normal year (2018), a year marked by the impact of the Covid19 pandemic (2020), and a year characterized by extremely high prices (2022).

Figure 8.4 illustrates the power balance in the years 2018, 2020, and 2022. Several observations can be made from the graphs. Firstly, the power peaks in 2022 are mainly divided into three distinct levels, whereas in the other two years, the peaks exhibit greater variation throughout the year. Secondly, all years experience their highest power peak in September, which either indicates a high power demand or low prices in this month. Furthermore, the power balance of 2018 and 2020 follows the same pattern in all the months except May, where 2018 obtain a higher peak than the previous month while the peak for 2020 is reduced compared to the month before. The white areas in the plots represent a constant production level sustained over several hours. Notably, the 2020 plot consists of more white areas than the two other years. This explains why all the power peaks obtained in 2020 are lower than the ones in 2022 and 2018, despite that the total load and energy demand of the system, remain the same in all years. It only exists a few white areas in the energy balance of 2022. This indicates significant price variations throughout the day, making the model maximize hydrogen production during hours with low prices.



2018 2020

2022

Figure 8.4: The power balance with day-ahead prices from 2018, 2020 and 2022

In addition, the load duration curve for hydrogen production in the years 2018, 2020, and 2022 is illustrated in figure 8.5. It is evident that the production of hydrogen is spread over more hours in 2018 and 2020 compared to 2022. In these two years, hydrogen was produced for approximately 7500 and 8200 hours. This can be attributed to the fact that the day-ahead price remained consistently low throughout these years. On the other hand, in 2022, the prices varied significantly from one hour to the next. To take advantage of the hours when the electricity price actually remained low in 2022, the model chose to produce at maximum capacity during these times. This can be seen in the plot for 2022, where the power demand is at its maximum, 170 MW, for approximately 4800 hours of the year. For 2018 and 2020 the highest power peaks appeared for around 2500 and 1900 hours, respectively.

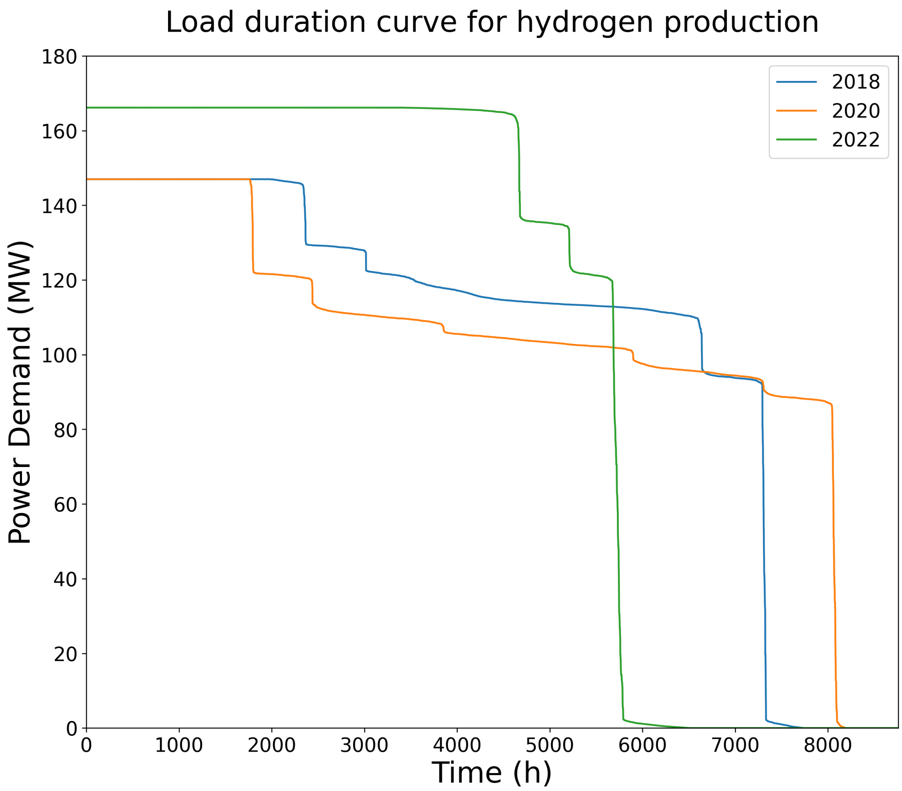


Figure 8.5: Load duration curve for hydrogen production with the day-ahead prices from 2018, 2020 and 2022

8.3 The port log

In this subsection the port log of Oslo is analyzed and changed to observe the impacts of the objective value, the total energy demand, hydrogen storage size, and electrolyser and transformer capacity. Since the port log will vary every year it lay some uncertainties in the actual load demand in the model simulated. Therefore, all the hydrogen demands above 10 tons per hour and power demand for charge power above 10 MW is removed.

Through an analysis of the hydrogen demand per hour for the entire port of Oslo, it can be determined that high peaks only occur for a few hours during the year. Table 8.1 provides information on the hydrogen demand per hour in port, and how many hours this amount appears. It reveals that the hydrogen demand peak exceeds 10 tons for only 37 hours in a year. For the majority of the year, the hydrogen demand per hour ranges between 0 and 5 tons.

Table 8.1: Hours with high hydrogen demand

Hydrogen demand per hour (tons)	**1<**	**5<**	**10<**	**15<**	**20<**
Total hours	5703	701	37	8	7

Figure 8.6 illustrates the hydrogen and charging demand per hour for Step 3. The analysis reveals that the power demand required for charging exhibits mainly one pronounced peak above 35 MW, which occurs in October. The remaining high power peaks are slightly above 10 MW. In contrast, the hydrogen demand, depicted in red, exhibits a few high peaks above 10 tons, while the majority of the hydrogen demand peaks are lower than 5 tons, as also displayed in the table 8.1.

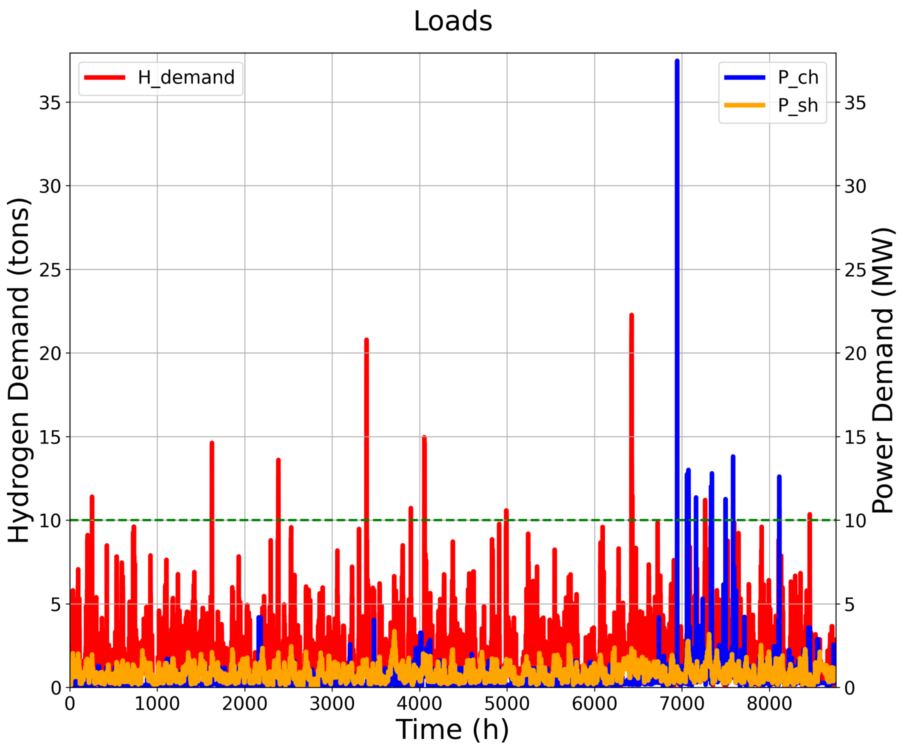


Figure 8.6: Loads of the port of Oslo for Step 3

By excluding 21 specific ships from the port of Oslo, the hydrogen demand peaks exceeding 10 tons and the high charge power demand peaks are mitigated. The particulars of the removed ships, including their varying types and sizes ranging from 44 GT to 17757 GT, are documented in table 11 in the appendix N.

Figure 8.7 illustrates the resulting loads of the port with the aforementioned ships removed. The remaining findings are presented in table 8.2. Eliminating the ships responsible for the high peaks significantly change the system's parameters and results. First of all, the total hydrogen demand is reduced by 490 tons. Furthermore, the hydrogen storage capacity decreased from 217 tons to 59 tons. This reduction has a direct impact on the electrolysis process, which now requires generating more power within a shorter time and therefore need an increased capacity. Therefore, the capacity of the electrolyser is raised from 166 MW to 236 MW. The changes in system parameters lead to a significant reduction in the total investment cost amounting to 400 million NOK. Additionally, the annual operation cost is reduced by 12 million NOK, making an overall reduction of 412 million NOK.

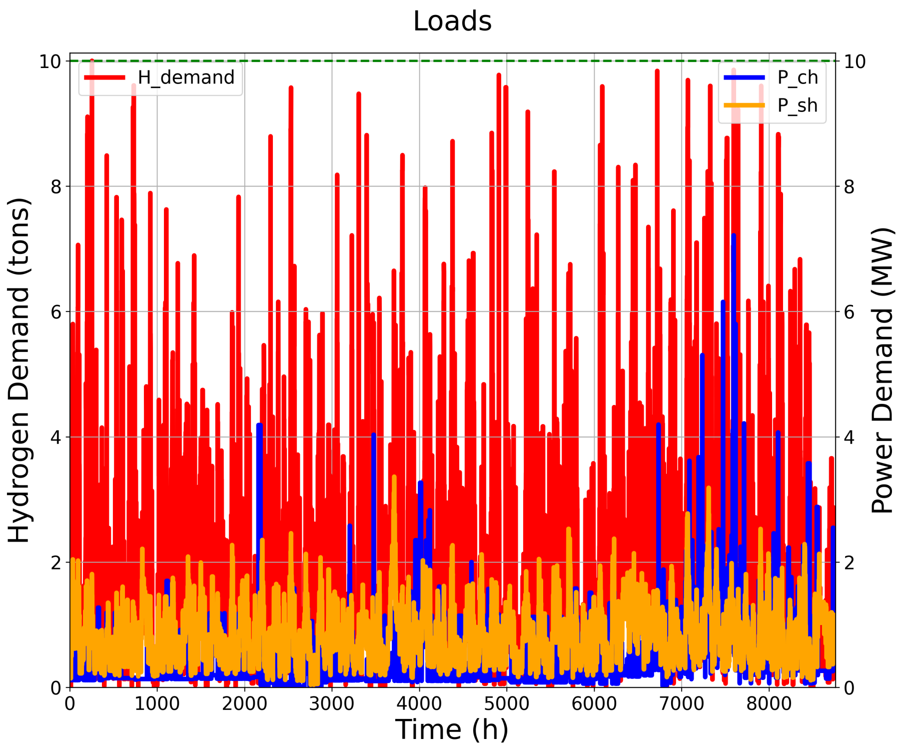


Figure 8.7: Hydrogen demand and power peaks per hour with removing of the ships which causes the high hydrogen and power peaks

Table 8.2: Comparison of the results by removing the 21 ships causing the high power and hydrogen demand peaks to Step 3

Description	Step 3	High peaks removal
Objective value (MNOK)	3935	3523
Total investment cost (MNOK)	2290	1890
Annual operation cost (MNOK)	1646	1633
Total energy demand (GWh)	923	899
Total energy demand for hydrogen production (GWh)	912	888
Total energy demand for charge power (GWh)	3,86	3,73
Total energy demand for shore power (GWh)	7,25	7,22
Hydrogen storage (tons)	217	59
Electrolysis capacity (MW)	166	236
Transformer capacity (MW)	170	240
Total hydrogen demand (tons)	18260	17770
Maximum hydrogen demand in one hour (tons)	22	10

8.4 Start value of the hydrogen storage

The impact of the start value for the hydrogen storage $H_{storage}^{start}$ is tested to see if it reduces the high power peak of January. The results from the tested start values, which are shown below, are compared to Step 3 having a hydrogen start and end value of 22.3 tons. The optimal result of the hydrogen storage was found to be 217 tons for Step 3. Therefore, for this sensitivity analysis, different percentages of this number were used as the start and end values of the hydrogen storage. It is also simulated for no start and end values.

$H_{\text{storage level}}$: 0 % , 25 % , 50% , 75 %, 100 %

The different storage levels are not affecting the simulated results for Step 3 in any mentionable way. The objective value is reduced by 15.8 million NOK from using zero as a start and end value to 217 tons as a start and end value. Furthermore, the hydrogen storage experience an increase of 1 ton, while the capacity of the electrolyser and transformer are reduced by 1 MW. Further details regarding these results are presented in appendix O.

8.5 Peak shaving

As previously discussed, the optimization model incorporates peak shaving by considering peak prices for each month. In this section, the Step 3 scenario with and without the implementation of peak prices is simulated. All other parameters remain constant between the two cases.

Figure 8.8 depicts the power peaks for each month of the year, comparing the scenarios with and without peak shaving. Without peak shaving, the power peaks consistently reach a maximum of 190 MW each month. In this case, the model does not consider the monthly price but instead maximizes production, within the optimal capacities, in the hours with the lowest day-ahead prices. In contrast, with peak shaving, the model strives to keep the peaks low due to the influence of the monthly peak price. As a result, the power peaks vary each month, ranging from 122 MW to 170 MW. The majority of the months' experience peaks between 167 MW and 170 MW.

Lastly, the system parameters; $H_{storage}$, P_{ely}, and P_{trafo}, have changed when considering the scenario without peak shaving. The electrolysis and transformer have as the picture indicates increased, while the hydrogen storage is reduced.

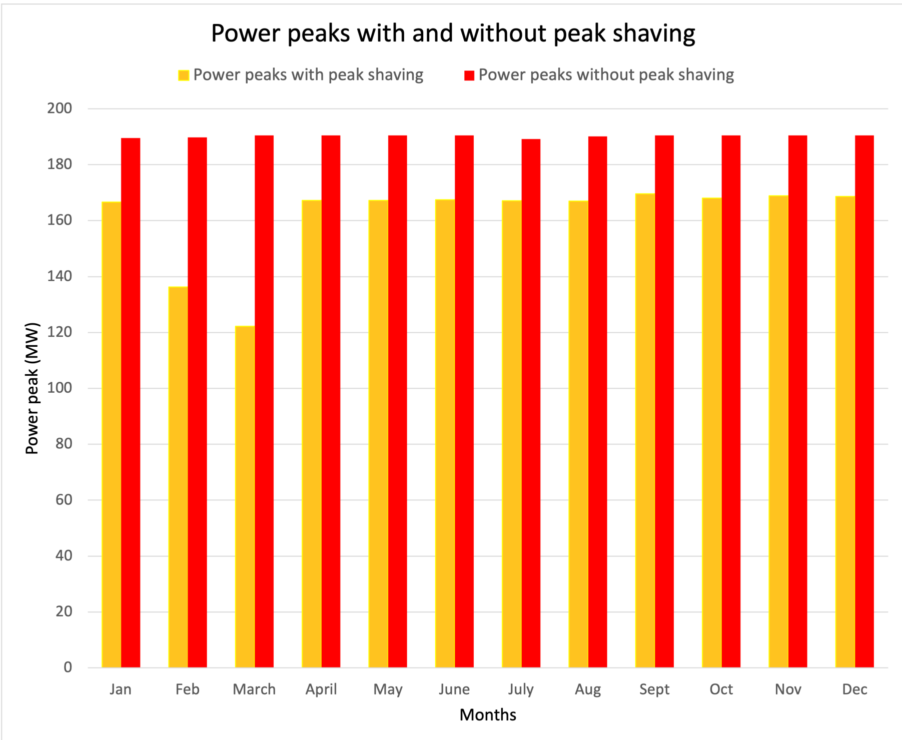


Figure 8.8: Power peaks each month of the year for Step 3 with and without the implementation of peak shaving

The revenue R for peak shaving can be calculated by equation (8.1). For Step 3, peak shaving reduces the annual operation cost by 16 MNOK.

$$R = \sum C_{peak,m} \cdot (P_{peak}^{org} - P_{peak}^{new}) \tag{8.1}$$

Chapter 9

Discussion

The discussion chapter will mainly evaluate the total energy demand, highest power peaks, and objective values from the six fuel mix scenarios, including the "Steps to the Future". The mentioned results are further sat in the context and compared to other facilities and industries with high power and energy demand with the goal to understand the impact of a zero-emission port on the power grid of Norway.

9.1 Comparison of simulation results

This section provides a comparative and analytical discussion of the results, focusing on the highest power peak, the total energy demand, and the objective value including operation and investment cost for Scenario 1 (all ships using hydrogen), Scenario 5 (Zero emission scenario), Step 1, Step 2, and Step 3 presented in section 7.3 and 7.4. It also incorporates some discussion regarding the findings of the sensitivity analysis.

Table 9.1 presents the results objected from the mentioned scenarios in addition to some of the results obtained from the sensitivity analysis. The analysis examines the highest power peaks for all scenarios to understand the required capacity of the transformer to handle all the demands. The lowest value presented in the column "Highest power peak" occurs in Step 1. This is expected since in Step 1 some ships are using conventional fuels. Consequently, the lowest value of the maximum power peaks considering all ships powered by green fuels is observed in Scenario 1, where all ships are fueled with hydrogen. However, it is important to note that shore power is not included in this scenario. Therefore, the actual lowest power peak is achieved in Step 3, with a difference of approximately 1 MW compared to the Zero emission mix.

Furthermore, the sensitivity analysis for Step 3 reveals two further conclusions regarding the highest power peak. The first aspect to consider is the peak can decrease to 151 MW if the simulation is based on day-ahead prices of 2020 instead of 2022. The other point is by considering the prices of 2022 again, a power peak of 151 MW is projected if the cost of the electrolyser increases by 50%.

Secondly, examining the total energy demand, Step 1 once again achieves the lowest value of 472 GWh. However, when accounting green fuel for all ships, Scenario 5 achieves the lowest energy demand of 728 GWh. The highest energy demand is observed in Scenario 1, reaching 924 GWh per year.

Lastly, the objective value is analyzed across all scenarios and sensitivity analyses. The solution with the lowest investment and operational cost is obtained in Step 1, equal to 1711 MNOK, while the highest value of 4416 MNOK is obtained in Step 3, where the price of hydrogen storage is increased by 50%. Furthermore, the sensitivity analysis shows by changing single input parameters like investment costs or day-ahead prices that the highest power peak varies from 151 MW to 294 MW.

Table 9.1: Comparison of the results from both the scenarios and sensitivity analysis

	Objective value (MNOK)	Total energy demand (GWh)	Highest power peak (MW)
Scenario 1: Hydrogen	3945	924	169
Scenario 5: Zero emission mix	3318	728	171
Step 1	1711	472	104
Step 2	2427	640	156
Step 3	3935	923	170
Investment costs (Electrolysis increased cost)	4416	923	151
Investment costs (Electrolysis reduced cost)	3222	923	294
Day- ahead prices: 2020	2438	923	151

9.2 Comparison of the total energy demand to other industries

In light of achieving a zero-emission maritime sector, the total energy demand of the port of Oslo is projected to exceed 923 GWh per year, according to Step 3. To gain a better perspective on this energy demand, a comparison is made with the energy demands of other major industries and facilities in Norway, as depicted in figure 9.1 [97]. The three green blocks in the figure represent the total energy demand in the port of Oslo for Step 1, Step 2 and Step 3. All these steps will reach a higher energy demand than all street and road lighting in Norway. Additionally, the energy demand of the port in both Step 2 and Step 3 are estimated to be higher than what the rail transport sector has today. Interestingly, among the chosen industries, the production of aluminum through electrolysis exhibits the highest energy demands, equivalent to 16800 GWh. The total energy of the aluminum demand is divided by seven producers which in total produce 1.2 million tons of aluminum within a year, with an energy demand of 12-15 MWh per ton of aluminum produced [98]. The total electricity demand for aluminum production is approximately 18 times the energy demand for Step 3. This indicates that even if the 18 biggest ports of Norway were operating as zero emission ports, the total energy demand will still remain below the aluminum production.

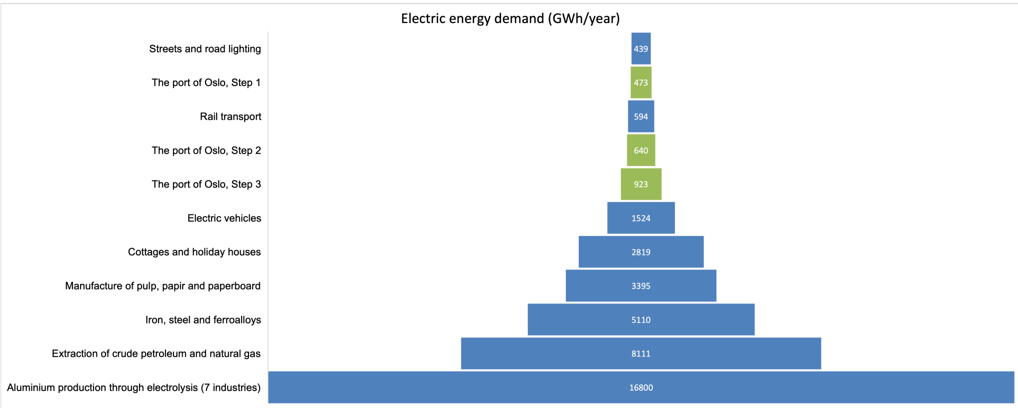


Figure 9.1: Energy demand for some industries in Norway [97], [98], [99]

9.3 Power grid

As discussed in section 2.2.1, the highest power peaks during the year affect the planning of the power grid capacities. This master thesis presents that the power peaks of different scenarios considering hydrogen vary from 104 MW to 170 MW and occur in almost every month of the year. If these peaks are added to hours of the year with already high power peaks the power grid as of today will not be able to handle it.

Currently, Statnett provides a capacity of 4400 MW to Oslo and Viken [38]. Exceeding this limit could lead to overloads which in practice would stop the power delivery to several consumers. Therefore, it is important not to connect more consumers to the power grid than it can handle. The port of Oslo currently has transformers with a total capacity of 36.7 MW. In Step 3, a combined capacity of 170 MW is required to meet the hydrogen demand during specific hours of the year. This indicates that the port needs to expand its transformer capacity and therefore also the cables and other equipment to a total of at least 134 MW. Even for Step 1, the port would need to almost triple the size of its transformer capacity to accommodate the high power peak of 104 MW. As of today, Scenario 4 (all ships are connected to shore power) is the only scenario that could be utilized without any new capacity in the transformer. However, Scenario 3 (all ships are plug-in hybrid) reaches a peak of 38 MW for only a few hours of the year, while most of the demand remains below 5 MW. Therefore this plug-in hybrid solution could be implemented with a simple quaying optimization of the ships in the port of Oslo. Furthermore, with a transformer capacity of 50 MW could approximately more than 50 % of the ships been full-electric (if that was technical possible for the ship)

Figure 9.2 illustrates the available capacity in Norway (on the left) and specifically in Oslo (on the right) on the DSO level. The red circles indicate that the available capacity ranges from 0 to 1 MW, the yellow circles represent an available capacity of 1-20 MW, while the green circles indicate a capacity exceeding 20 MW. However, as depicted in the figure, only three locations in Norway have an available capacity exceeding 20 MW. These areas are Ulefoss, Knarvik, and Litlesotra. For the area near the port of Oslo, there is currently no available capacity [100].

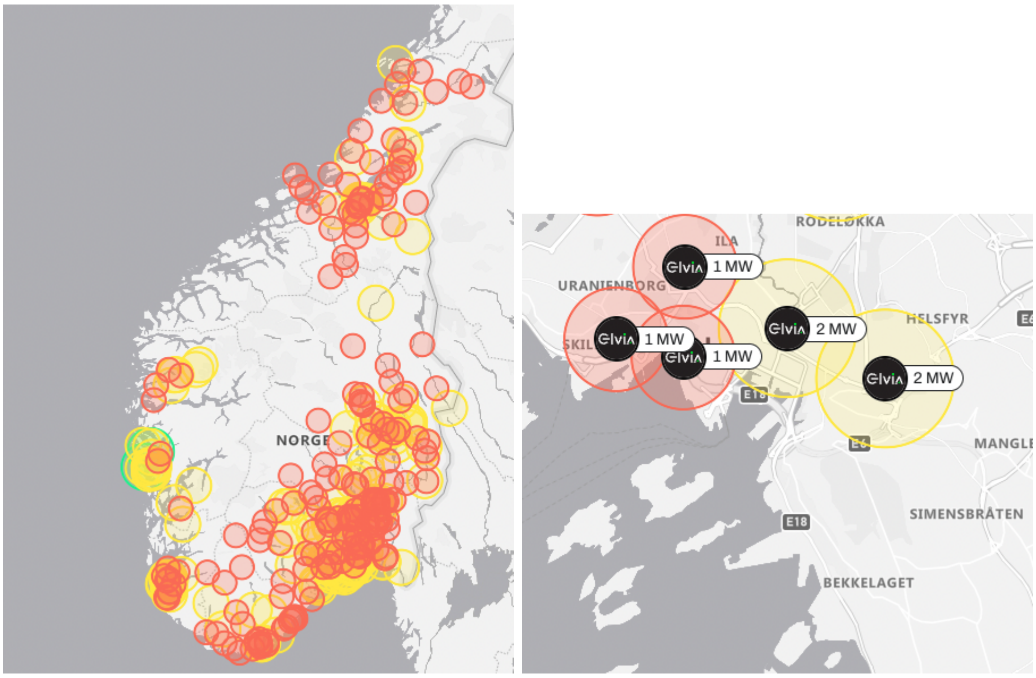


Figure 9.2: Overview of the available capacities in the distribution grid in Norway today [100]

However, Statnett is currently in the process of expanding and modernizing the central electricity grid that supplies power to Oslo. The grid has not undergone significant updates in the past two decades [38]. According to [38], the projected power demand in 2050 could reach 6800 MW. Consequently, the grid needs to be appropriately designed to handle this increase. However, in the mentioned analysis of [38], the use of green fuels and the production of hydrogen for the port of Oslo is not considered. The power demands presented in this master thesis emphasize once again that future power predictions should include a detailed analysis of the maritime sector.

9.4 Comparison with other sources

In a study by [8], a simplified estimation of hydrogen demand at the port of Oslo was made using the port log from 2018. The estimation only considered ships below 5000 GT (size categories 1 and 2), traveling less than 278 km from the port, and excluding all passenger and cruise ships. Based on these assumptions, the total hydrogen demand was estimated to be 140 tons per year for 731 ships. The report briefly mentions that if the distance were between 555-926 km, the total hydrogen demand would be 112 tons for only 39 ships in the same size category. This demonstrates the significance of considering the travel distance of ships in the calculation.

In contrast, the total hydrogen demand in all tested scenarios in this master thesis is significantly higher. This is primarily because it is assumed that a larger portion of the ship segments will be fueled with pure hydrogen, methanol, or ammonia. Additionally, the hydrogen demand is based on the average distance traveled by ships in that particular ship segment. Investigating table 5.2 it can be found that for this model, 112 general cargo ships in ship size category 1 would require 112 tons of hydrogen. However, if all the general cargo were in ship size category 2 instead, only 16 ships would generate the same demand of 112 tons. Therefore, it should be noted that due to the limited knowledge of the exact distances sailed by all the ships, the results of this master's thesis may deviate from the actual reality.

9.5 Uncertainties in the load model

When discussing the results, it is essential to remember that the load inputs are based on general demands derived from ship type and size. However, in reality, there are various factors that influence the energy requirements and, consequently, the demand for hydrogen or power in a ship. For example, the distance traveled by a ship plays a crucial role. This master thesis utilized input data based on the average consumption for a ship segment. Meaning, the average sailing distance is included. However, for a more detailed analysis, the distance per ship is required. Moreover, ships within the same ship segment may exhibit varying energy demands depending on their specific purpose. There can also be significant differences between ships within the same size category, considering the range of 5000 GT in each category. Additional factors such as maneuvering, speed, and acceleration further impact the overall energy demand for each ship's propulsion. These factors contribute to the complexity of accurately estimating the energy demand for each of the different ships in each ship segment [7].

Furthermore, it should be noted that the technology related to hydrogen, including alternative fuels such as methanol and ammonia, is still in the developmental stage. The specific allocation of these fuels across different ship segments in the market remains uncertain as described in chapter 3. In addition, the efficiency factor by converting hydrogen to methanol and ammonia is not considered in this master thesis. Moreover, this master's thesis has been using historical data for one year regarding the port log, solar power production and electricity prices. However, these parameters change every year due to weather conditions and economic reasons among others. Therefore, the outcomes of this study may vary for different years. Lastly, the projected growth in the maritime sector has not been accounted for in this study.

Nevertheless, the results obtained from this study contribute to providing an overview of the approximate total energy, power, and hydrogen demand that may emerge in the future. The primary purpose of this study is to raise awareness among stakeholders and industry participants regarding the projected demand, enabling them to plan and adapt their infrastructure and capacities accordingly. By doing so, they can better prepare for the anticipated changes and requirements in the maritime sector.

Chapter 10

Conclusion

This master thesis has analyzed opportunities for zero-emission ports, using the port of Oslo as a case study. Therefore, an optimization model with multiple purposes has been developed to minimize the costs of the energy system in port for several created scenarios toward a greener maritime sector. This includes a special focus on shore power, charge power for full-electric and plug-in hybrid ships and the local production of green hydrogen for hydrogen-driven ships. Consequently, this consists of the annual operation costs as well as the total investment costs for the additional installed components as electrolyser, transformer, and hydrogen tank to cover all the demands. Furthermore, it is proposed to supplement the power supply from the Norwegian grid with its own PV powerplant on the useable areas in the port of Oslo which is also enclosed in the developed program. Due to all these functions, the model is able to find an optimal solution for the different created scenarios regarding the annual operation cost, total investment cost and the ideal dimensions for the needed components. Moreover, it also outputs the computed power, energy and hydrogen demand to improve the planning of the future power supply in the port. To verify the results of the model a sensitivity analysis is conducted to test the impact of the different system parameters.

To be able to apply this optimization to every port of Norway the model is split up into three parts “Load Model”, “Electricity Price Model”, and “Optimization Model” which are designed in a generalized manner. The ”Load Model” determines the total loads included in the port, considering hydrogen, shore power, and charge power per hour throughout the year. n addition, the energy production from local solar panels is included. The ”Optimization Model” uses the calculated loads, in addition to the hourly electricity prices and grid tariffs of the ”Electricity Price Model” to determine an optimal production of hydrogen based on the total costs. The ”Optimization Model” is divided into two optimization problems ”Optimal operation” and ”Operation and investment optimization”. ”Optimal operation” optimizes the operation cost for energy in a port where the capacities of the electrolyser, transformer and hydrogen storage already exists. The second optimization problem, ”Operation and investment optimization” includes finding the optimal sizes of the electrolyser, transformer and storage, in addition to the production pattern throughout the year by minimizing both the annual operation and total investment cost.

The conclusions of this study are based on the analysis of six created fuel mix scenarios, with the especially developed ”Steps to the Future” considered the most realistic and promising scenario. The ”Steps to the Future” scenario aims to illustrate the varying outcomes resulting from the implementation of different mixes of green fuels over three distinct time periods. Each step represents a technological improvement and increased adoption of hydrogen in the maritime sector. Summarizing the results, the implementation of shore power for all connected ships is estimated to require approximately 7 GWh for a year with a power peak reaching 3 MW. This implementation, assumed to be initiated from Step 1, has the potential to significantly reduce CO2 emissions in the port of Oslo by approximately 4505 tons per year. Furthermore, in Step 3, where all ships are either green hybrids or fueled with hydrogen, the overall energy demand is calculated to be 923 GWh. Additionally, the highest power peak observed in this step, and thus the capacity required for the transformer, is estimated to be 170 MW. This is 4.7 times greater than the existing transformer capacity in the port and also exceeds by far the available capacity of the current power grid in Oslo. Such power analysis aids TSO, DSO and regulator authorities in predicting future power demand and reinforcing the grid to accommodate these requirements. The study also predicts a substantial CO2 reduction of approximately 215422 tons per year in Step 3, highlighting the significant environmental benefits associated with the widespread adoption of green fuels and technologies.

Furthermore, the model provides an estimation of the potential hydrogen demand at the port of Oslo if vessels transition to zero-emission propulsion fueled by green hydrogen. The hydrogen demand in this thesis represents all versions of hydrogen, including methanol and ammonia, and was calculated to be 18260 tons for Step 3. This information is valuable for firms already involved in green hydrogen production or those considering entering the market, as it offers insights into future customer demand and market opportunities.

The sensitivity analysis indicates that the operational costs can vary by a factor of 3.5 depending on the day-ahead prices from a former average year with 459 MNOK (2018) and an extreme year with 1646 MNOK (2022). Therefore, predicting the actual operational cost during the implementation of Step 3, which involves the fuel demand in the future, proves challenging. However, the electricity prices are assumed to be higher than in previous years, yet potentially lower than in 2022 [101]. Additionally, the model illustrates that implementing peak shaving can result in savings of approximately 16 MNOK in the operational cost calculated for the year 2022, and should therefore be considered.

Lastly, the model presents the total energy generated from the installed PV modules at the port. In this study, 15 000 modules were implemented, resulting in a total production of 3.8 MWh and a cost reduction of approximately 7 MNOK per year in operation costs. Based on predictions of investment costs from other analyses, it is concluded that the installation of PV modules would be beneficial for the port after approximately 6 years in this case study.

In conclusion, the results from this case study confirm the importance of developing detailed models and conducting thorough analyses of multiple scenarios to determine future power, energy, and hydrogen demand for the maritime sector. These insights are crucial for informing infrastructure planning and ensuring that the necessary facilities and resources are built and allocated accordingly.

Chapter 11

Further work

In this master thesis, there have been made some assumptions for the model in order not to exceed the scope of this work. Consequently, there are still opportunities for further enhancements and implementations within the mentioned models to improve their functionality and performance.

Implementation battery system in port
The only flexible component incorporated in this master's thesis model is the production of hydrogen, achieved through the implementation of electrolysis and hydrogen storage. The two optimization problems minimize the operation cost considering both the electricity price and grid tariff. This optimization approach ensures hydrogen production during the cheapest hours of the day, while simultaneously minimizing power peaks and fulfilling the hourly demand for hydrogen. Regarding charge power and shore power, the electricity demand is directly purchased from the power grid. Consequently, if multiple full-electric ships dock at the port simultaneously, it leads to high power peaks in the electricity demand from the grid. This phenomenon was particularly illustrated in the "Zero emission mix" scenario presented in section (7.3), where the highest power peaks of the optimization were caused by charge power for the two smallest ship size categories. Based on these findings, it is recommended to implement a battery system within the port. This battery system would operate similarly to electrolysis by strategically distributing the electricity purchased from the grid during off-peak hours. By adopting this approach, both the high power peaks and operational costs can be effectively reduced.

Economic analysis of the port
To achieve a more complex economic analysis of the zero-emission port, it is advisable to include possible incomes of the green fuel and its by-products into the model. The selling price of both the electricity and the hydrogen fuel for the ship in port can easily be added to the objective function of the "Optimal operation" model as presented in (11.1).

$$\begin{aligned} \min \sum_{t \in T} C_{el,t} \cdot P_{grid,t} &+ \sum_{m \in M} (C_{peak,m} \cdot P_{peak,m} + C_{fixed,m}) \\ - \sum_{t \in T} (H_{demand,t} \cdot C_{hsold,t}) &- \sum_{t \in T} (P_{sh,t} + P_{ch,t}) \cdot C_{elsold,t} \end{aligned} \tag{11.1}$$

where
$C_{hsold,t}$ is the selling price of hydrogen
$C_{elsold,t}$ is the selling price of the electricity

Moreover, it should be noted that the by-product of hydrogen production at the port is oxygen, as discussed in subsection 2.1.2. There is potential to include the price of selling this oxygen to pharmacies or other companies in need. However, further investigation is required to determine the market value and demand for oxygen. Furthermore, with the implementation of the battery system, the port could also sell excess power back to the grid during hours of high demand. This would not only contribute to a reduction in operational costs but also optimize the utilization of the battery.

The investment costs considered in this master thesis are mainly used to determine the right size and capacities of the electrolyser, hydrogen storage, and transformer rather than finding the exact right price. As presented in section 2.5, there relay uncertainties in the investment cost for the electrolyser, hydrogen storage and transformer. To achieve a more realistic total investment cost all the necessary equipment regarding implementing charge and shore power at the port, the price of a compressor, bunkering and other auxiliaries for the hydrogen system should be included.

Furthermore, this master's thesis considers the total investment cost instead of an annual cost, primarily due to the uncertainties discussed in section 2.6 and the scope of this study. However, for achieving more precise results, it is recommended to incorporate a business analysis for the port into the model and to gather more insight knowledge about the development of the hydrogen market.

Further suggestion to reduce high power peaks
If the objective of the analysis is to minimize power peaks more than what this master thesis has conducted, several implementations can be explored and tested in future work. Firstly, as demonstrated in the sensitivity analysis (Section 8.1), increasing the investment cost for electrolysis in this master's thesis resulted in a 19 MW reduction in the highest power peak. Conducting further analysis with a larger disparity in investment costs between electrolysis and hydrogen storage could potentially result in a greater reduction in power peaks. However, it should be noted that the minimum required capacity in the electrolysis leads to bigger hydrogen storage.

Moreover, it would be valuable to investigate the impact of consistently higher grid tariffs throughout the year, as compared to the prices considered in this master's thesis which change in the summer and winter seasons. Lastly, exploring and optimizing the port log can play a significant role in the analysis. The high power peaks resulting from hydrogen production are primarily attributed to ships arriving during overlapping time periods and having short stays at the port. By examining and optimizing the port log, it is possible to devise strategies that distribute the arrival and departure times of ships more evenly, thereby reducing the high demand and high power peaks.

More detailed analysis of the port of interest
The analysis of this master thesis considered seven of the quay areas included in the port of Oslo. However, to achieve a more detailed analysis the developed model could be utilized for one quay area at a time.

Moreover, as part of this master's thesis, an additional Python script has been developed to examine the frequency of each ship's arrivals at the port of Oslo throughout the year. By utilizing the analysis script, it is possible to conduct a new analysis focusing exclusively on the ships with higher arrival frequencies. This approach allows for a more targeted investigation of green fuel options specifically for the ships that have more frequent visits and it can be obtained a more detailed result.

More detailed implementation of hydrogen production and utilization
In this master's thesis, the production and bunkering of hydrogen have been simplified, considering only the maximum capacity of the electrolyser and hydrogen storage as constraints. However, future work should focus on investigating and implementing more realistic and detailed constraints regarding the production of hydrogen. For example, constraints such as the ramping rate of the electrolyser and the bunkering rate of hydrogen should be considered. According to [102], the maximum bunkering rate of liquid and compressed hydrogen is 2400 kg/hour and 900 kg/hour, respectively. Depending on the number of filling stations in port, the bunkering rate may require a longer dock period for ships that have a higher demand than the bunkering rate can accommodate.

Include more historical and detailed data as input data
The available data of this master thesis were limited. To conduct a more comprehensive analysis, it is recommended to utilize the developed models with historical data considering the port log, solar power generation, and electricity prices. This would provide a more detailed understanding of the system dynamics and allow for more accurate predictions and optimizations.

Furthermore, incorporating more detailed information per ship, particularly regarding the travel routes, would significantly improve the accuracy of energy demand calculations.

Moreover, the results obtained in this master's thesis reveal a power demand ranging from 104 MW to 170 MW considering the "Steps to the Future" (section 7.4) scenario. This indicates that the transformers of the port should be connected to a higher power grid level than assumed in this master thesis. Therefore, it is highly recommended that further analysis involves engaging with the local Distribution System Operator (DSO), such as ELVIA in this case, to accurately assess the available grid capacity and the corresponding grid tariff. This would provide a more realistic assessment of the operational costs and financial implications associated with the high power demands of the zero-emission port.

Including efficiencies of ammonia and methanol
This master's thesis has considered the hydrogen demand as both direct hydrogen and through the hydrogen carriers methanol and ammonia. However, there is potential for further analysis to include the efficiencies associated with the conversion of pure hydrogen to ammonia and methanol to achieve a more realistic result.

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Appendix

A Input data for PV production

Table 1 shows the input parameters utilized in the extern PV script to provide the input data considered in this master thesis [53].

Table 1: The input data considered in the extern Python script to calculate the power production from one PV module

Parameter	**Input data**
Pmpp	255.22
Voc	37.8
Isc	8.89
T0	298.15
E0	1000
η_{inv}	0.9
NOCT	45.7

B Ideal gas law

The ideal gas law is used to calculate between the different units of measurement given in section 2.5.2, where the prices of hydrogen storage and electrolysis are presented. The ideal gas law is given below [103]:

$$PV = n \cdot R \cdot T \tag{2}$$

where:

P= Pressure (atm)
V= Volume (L)
n= Number of moles of gas (mol)
R= The universal gas constant (L · atm /K · mol)
T= The absolute temperature (K)

C ENOVA

Figure 1 present the locations in Norway that applied for support for implementing green hydrogen production. The red arrows point out the five places that recived the support.

Figure 1: Location that applied and received support from ENOVA to build green hydrogen production plants [87] [88]

D Gross tonnage

The gross tonnage of a ship is calculated by the following formula [104]:

$$GT = V \cdot K, \tag{3}$$

where;
V: total volume of the ship (m^3)
K: a nonlinear multiplier based on the ship volume

$$K = 0.2 + 0.02 \cdot \log_{10}(V) \tag{4}$$

E Charge Matrix

Table 2 displays the energy demand for the full electric ships given in kWh required for one trip based on calculation from the hydrogen matrix 5.2.

Table 2: Energy demand for the full electric ships given in kWh required for one trip based on calculation from the hydrogen matrix 5.2.

Ship type	GT1	GT2	GT3	GT4	GT5	GT6	GT7
Oil tankers	73700	257950	313225	1234475	737000	1123925	2045175
Chemical/product tankers	36850	147400	294800	479050	571175	0	0
Gas tankers	36850	110550	331650	515900	497475	1953050	3113825
Bulk carriers	36850	147400	165825	442200	737000	865975	479050
General cargo ships	18425	128975	276375	681725	257950	0	0
Containership	18425	36850	110550	73700	0	0	0
Ro-Ro cargo	36850	847550	128975	313225	128975	294800	0
Reefer/freezer ships	147400	405350	681725	0	0	0	0
Offshore supply ships	128975	350075	1050225	0	0	0	0
Other offshore service	73700	257950	994950	2137300	571175	0	0
Fishing vessels	73700	571175	5269550	0	0	0	0
Other activities	36850	276375	1160775	3629725	9967925	0	0

F Results with and without PV production in port

Table 3: Results with and with PV production in port

Description	With PV	Without PV
Objective value (MNOK)	3946.43	3953.86
Total investment cost (MNOK)	2300.82	2300.83
Annual operation cost (MNOK)	1645.61	1653.03
Total energy demand (GWh)	924.91	924.91
Total energy demand for hydrogen production (GWh)	924.91	924.91
Highest power peak (MW)	168.81	168.82
Utilization [h]	5478.86	5478.69
Load factor [p.u.]	0.63	0.63
Hydrogen storage (tons)	216.50	216.49
Electrolysis capacity (MW)	168.81	168.82
Transformer capacity (MW)	168.81	168.82
Total energy bought from the power grid (GWh)	921.09	924.91
Total energy produced by PV (GWh)	3.82	0.00

G Power demand for the Green Hybrids ship in Step 1

Table 4 present the energy demand given in kWh that is covered by battery for the "Green Hybrids" which is utilized in the "Steps to the Future". The table was utilized as an input table and therefore the names in the "Ship type" column are written and presented in Norwegian.

Table 4: Input matrix of the energy demand given in kWh utilized by the "Steps to the Future" to calculate the energy demand of "Green Hybrid"

Ship type	GT1	GT2	GT3	GT4	GT5	GT6	GT7
Oljetankskip	0	0	0	0	0	0	0
Kjemikalieskip	0	0	0	0	0	0	0
Gasstankskip	0	0	0	0	0	0	0
Bulkskip	0	0	0	0	0	0	0
Stykkgodsskip	3132,25	0	0	0	0	0	0
Containerskip	3132,25	0	0	0	0	0	0
Ro-ro frakteskip	2948	0	0	0	0	0	0
Fryseskip	0	0	0	0	0	0	0
Passasjerskip	0	0	0	0	0	0	0
Offshore supplyskip	14187,25	0	0	0	0	0	0
Andre offshore	11792	0	0	0	0	0	0
Fiskefartøy	8107	0	0	0	0	0	0
Andre aktiviteter	11055	0	0	0	0	0	0
Slepefartøy og skyvefartøy	11792	0	0	0	0	0	0
Bilskip	2948	0	0	0	0	0	0
Andre passasjerfartøy	36850	99495	220547,25	0	0	0	0
Lektere til tørrlast	0	0	0	0	0	0	0
Kombinert stykkegods-/bulkskip	2901,94	0	0	0	0	0	0
Arbeidsskip	11055	0	0	0	0	0	0
Andre tørrlastskip	0	0	0	0	0	0	0
Forskingsfartøy	11055	0	0	0	0	0	0
Bergingsfartøy og redningsfartøy	11055	0	0	0	0	0	0
Fritidsbåt/yacht	0	0	0	0	0	0	0
Fryse-/kjøleskip	0	0	0	0	0	0	0

H Hydrogen demand in Step 1

Table 5 present the input data considering hydrogen demand given in kg for each ship segment considered in Step 1. The yellow squares represent the hydrogen demand for the "Green Hybrid" ships, while the green squares represent the total energy demand covered by hydrogen. The table was utilized as an input table and therefore the names in the "Ship type" column are written and presented in Norwegian.

Table 5: The input matrix for hydrogen demand given in kg per trip in Step 1

Ship type	GT1	GT2	GT3	GT4	GT5	GT6	GT7
Oljetankskip	4000	14000	0	0	0	0	0
Kjemikalieskip	2000	8000	0	0	0	0	0
Gasstankskip	2000	6000	0	0	0	0	0
Bulkskip	2000	8000	9000	0	0	0	0
Stykkgodsskip	830	7000	0	0	0	0	0
Containerskip	830	2000	6000	4000	0	0	0
Ro-ro frakteskip	1840	0	7000	0	7000	0	0
Fryseskip	8000	0	0	0	0	0	0
Passasjerskip	0	0	0	0	0	0	0
Offshore supplyskip	6230	0	0	0	0	0	0
Andre offshore	3360	0	0	0	0	0	0
Fiskefartøy	3560	0	0	0	0	0	0
Andre aktiviteter	1400	0	0	0	0	0	0
Slepefartøy og skyvefartøy	3360	0	0	0	0	0	0
Bilskip	1840	0	7000	0	7000	0	0
Andre passasjerfartøy	0	9600	51030	0	0	0	0
Lektere til tørrlast	2000	8000	9000	0	0	0	0
Kombinert stykkegods-/bulkskip	1342,5	7500	9000	0	0	0	0
Arbeidsskip	1400	0	0	0	0	0	0
Andre tørrlastskip	2000	8000	9000	0	0	0	0
Forskingsfartøy	1400	0	0	0	0	0	0
Bergingsfartøy og redningsfartøy	1400			0	0	0	0
Fritidsbåt/yacht	0	0	0	0	0	0	0
Fryse-/kjøleskip	8000	0	0	0	0	0	0

I Results of the ”Step to the Future” scenario

Table 6 presents the results for each step in the ”Steps to the Future” scenario where the start capacity of the transformer is included.

Table 6: Results for each of steps to the future

	Description	Step 1	Step 2	Step 3
Total Energy demand	For the entire port (GWh)	473	640	923
	For hydrogen production (GWh)	462	629	912
	For charge power (GWh)	4	4	4
	For shore power (GWh)	7	7	7
Power and hydrogen demand	Highest power peak (MW)	104	156	170
	Total hydrogen demand in one year (tons)	9248	12598	18260
	Maximum hydrogen demand in one hour (tons)	10	11	22
Capacities	Hydrogen storage (tons)	36	52	217
	Electrolysis capacity (MW)	100	152	166
	Transformer capacity (MW)	104	156	170
Economy	Annual operation cost (MNOK)	849	1134	1646
	Total investment cost (MNOK)	853	431	997

J Detailed results from the ”Steps to the Future” simulation

Table 7 displays the results of the ”Steps to the Future” scenario when each of the steps are considered independent scenarios.

Table 7: Results regarding Step 1, Step 2 and Step 3 as independent scenarios

Description	Step 1	Step 2	Step 3
Objective value (MNOK)	1711	2427	3935
Total investment cost (MNOK)	862	1293	2290
Annual operation cost (MNOK)	849	1134	1646
Total energy demand (GWh)	473	640	923
Total energy demand for hydrogen production (GWh)	462	629	912
Total energy demand for charge power (GWh)	4	4	4
Total energy demand for shore power (GWh)	7	7	7
Highest power peak (MW)	104	156	170
Utilization time (h)	4535	4105	5442
Load factor (p.u)	0.5	0.4	0.6
Hydrogen storage (tons)	36	52	217
Electrolysis capacity (MW)	100	152	166
Transformer capacity (MW)	104	156	170
Total energy bought from the power grid (GWh)	469	637	919
Total energy produced by PV (GWh)	4	4	4
Sum hydrogen demand	9248	12598	18260
Maximum hydrogen demand in one hour (tons)	10	11	22

K CO2 Calculation

Table 8 present the conversion factors utilized to calculate from a hydrogen and power demand to CO2 emission. To simplify, it assumed that all the ships today utilize diesel and that the efficiencies of the electric engines are neglected.

Table 8: The conversion factors for CO2 emission calculation

Conversion factors	**Abbreviation**	**Value**
Energy density diesel	ED	10.1 (kWh/l)
Energy efficiency of the diesel engine	η_{diesel}	0.4
Fuel cell efficiency	η_{fc}	0.55
LHV	LHV	33.33 (kWh/kg)
CO2 emission factor based on diesel	EF	2.6 (kg CO2/liter)
Total hydrogen demand (kg)	Tot_{hyd}	
Total energy demand (kWh)	Tot_{energy}	

Equation 5 presents the calculation from the hydrogen demand to CO2 emission. The second equation 6 present the calculation from the energy demand.

$$CO2_{emission}(kg) = \frac{Tot_{hyd} \cdot LHV \cdot \eta_{fc} \cdot EF}{ED \cdot \eta_{diesel}} \tag{5}$$

$$CO2_{emission}(kg) = \frac{Tot_{energy} \cdot EF}{\eta_{diesel} \cdot ED} \tag{6}$$

L Results from sensitivity analysis with different investment costs

Table 9 presents the results obtained in the sensitivity analysis considering different values of the total investment costs for an electrolysis, hydrogen storage and transformer.

Table 9: Comparison of the result considering different total investment costs for the electrolysis, hydrogen storage and transformer

Investment cost	**Original**	**Electrolyser**		**Hydrogen storage**		**Transformer**	
	Step 3	↑	↓	↑	↓	↑	↓
Objective value (MNOK)	3935	4416	3222	4436	3301	3955	3914
Total investment cost (MNOK)	2290	2737	1612	2828	1622	2306	2275
annual operation cost (MNOK)	1646	1679	1610	1608	1679	1650	1640
Total energy demand (GWh)	923	923	923	923	923	923	923
Total energy demand for hydrogen production (GWh)	912	912	912	912	912	912	912
Total energy demand for charge power (GWh)	4	4	4	4	4	4	4
Total energy demand for shore power (GWh)	7	7	7	7	7	7	7
Highest power peak (MW)	170	151	294	227	151	166	175
Utilization (h)	5442	6112	3143	4075	6114	5572	5280
Load factor (p.u)	1	1	0	0	1	1	1
Hydrogen storage (tons)	217	237	112	165	237	221	212
Electrolysis capacity (MW)	166	147	290	223	147	163	171
Transformer capacity (MW)	170	151	294	227	151	166	175
Total energy bought from the power grid (GWh)	919	919	919	919	919	919	919
Total energy produced by PV (GWh)	4	4	4	4	4	4	4
Total hydrogen demand (tons)	18260	18260	18260	18260	18260	18260	18260
Maximum hydrogen demand in one hour (tons)	22	22	22	22	22	22	22

M Comparison of results considering different day-ahead prices

Table 10: Comparison of results considering day-ahead prices from 2018, 2019, 2020, 2021 and 2022

	Day-ahead prices				
Decribtion	**2018**	**2019**	**2020**	**2021**	**2022**
Objective value	2726	2705	2438	2997	3935
Total investment cost	2267	2267	2267	2267	2290
Annual operation cost	459	438	172	730	1646
Total energy demand (GWh)	923	923	923	923	923
Total energy demand for hydrogen production (GWh)	912	912	912	912	912
Total energy demand for charge power (GWh)	4	4	4	4	4
Total energy demand for shore power (GWh)	7	7	7	7	7
Highest power peak (MW)	151	151	151	151	170
Utilization (h)	6117	6116	6116	6120	5442
Load factor (p.u)	0,70	1	0,70	1	0,62
Hydrogen storage (tons)	237	237	237	237	217
Electrolysis capacity (MW)	147	147	147	147	166
Transformer capacity (MW)	151	151	151	151	170
Total energy bought from the power grid (GWh)	919	919	919	919	919
Total energy produced by PV (GWh)	4	4	4	4	4
Total hydrogen demand (tons)	18260	18260	18260	18260	18260
max hydrogen demand in one hour (tons)	22	22	22	22	22

N Removal of the ships that causes the high demand peaks

Table 11: The ships that cause the high single demand peaks in the model

Arrival	Departure	SkipType	SkipBT
11.01.2018 12:20	11.01.2018 22:10	Oljetankskip	4801
09.03.2018 02:40	09.03.2018 19:35	Oljetankskip	11463
09.03.2018 17:20	09.03.2018 19:45	Kjemikalieskip	9546
10.04.2018 02:00	10.04.2018 11:00	Oljetankskip	11701
22.05.2018 08:15	22.05.2018 12:05	Oljetankskip	11463
12.06.2018 12:00	12.06.2018 13:05	Stykkgodsskip	2728
18.06.2018 22:30	19.06.2018 03:40	Oljetankskip	17757
27.07.2018 22:00	28.07.2018 04:10	Containerskip	9957
25.09.2018 13:39	25.09.2018 18:00	Oljetankskip	17757
25.09.2018 18:10	26.09.2018 02:24	Oljetankskip	17757
17.10.2018 08:43	17.10.2018 09:55	Andre passasjerfartøy	98
22.10.2018 01:39	22.10.2018 02:16	Slepefartøy og skyvefartøy	292
22.10.2018 18:10	22.10.2018 18:52	Slepefartøy og skyvefartøy	292
26.10.2018 08:46	26.10.2018 09:35	Forskningsfartøy	44
30.10.2018 16:05	30.10.2018 19:40	Stykkgodsskip	7409
02.11.2018 12:23	02.11.2018 13:14	Slepefartøy og skyvefartøy	292
02.11.2018 22:01	02.11.2018 22:40	Slepefartøy og skyvefartøy	292
09.11.2018 10:04	09.11.2018 10:45	Arbeidsskip	57
13.11.2018 00:04	13.11.2018 00:36	Slepefartøy og skyvefartøy	292
05.12.2018 00:55	05.12.2018 01:26	Slepefartøy og skyvefartøy	292
19.12.2018 12:34	19.12.2018 13:55	Stykkgodsskip	2728

O Comparison of results considering different hydrogen storage start values

Table 12 presents the result considering different hydrogen storage start values based on a percentage of the maximum hydrogen storage capacity.

Table 12: Comparison of the results considering different hydrogen storage start values based on maximum storage capacity

	Hydrogen storage start value					
Description	**0 %**	**25 %**	**50 %**	**75 %**	**100 %**	**Original**
Objective value (MNOK)	3936.9	3932.7	3928.5	3921.1	3921.1	3935.2
Total investment cost (MNOK)	2289.6	2289.2	2289.0	2288.2	2288.2	2289.6
Annual operation cost (MNOK)	1647.3	1643.5	1639.4	1632.9	1632.9	1645.6
Total energy demand (GWh)	924.1	921.4	918.7	913.2	913.2	923.0
Total energy demand for hydrogen production (GWh)	913.0	910.3	907.6	902.1	902.1	911.9
Total energy demand for charge power (GWh)	3.9	3.9	3.9	3.9	3.9	3.9
Total energy demand for shore power (GWh)	7.3	7.3	7.3	7.3	7.3	7.3
Highest power peak (MW)	169.6	169.3	169.2	168.5	168.5	169.6
Utilization time (h)	5448.0	5442.6	5430.3	5420.9	5421.1	5441.5
Load factor (p.u)	0.6	0.6	0.6	0.6	0.6	0.6
Hydrogen storage (tons)	217.5	217.8	217.9	218.6	218.6	217.5
Electrolysis capacity (MW)	166.2	165.9	165.7	165.0	165.0	166.2
Transformer capacity (MW)	169.6	169.3	169.2	168.5	168.5	169.6
Total energy bought from the power grid (GWh)	920.3	917.6	914.8	909.4	909.4	919.2
Total energy produced by PV (GWh)	3.8	3.8	3.8	3.8	3.8	3.8
Total hydrogen demand (tons)	18260.3	18260.3	18260.3	18260.3	18260.3	18260.3
max hydrogen demand in one hour (tons)	22.3	22.3	22.3	22.3	22.3	22.3

P Python scripts

This subsection presents the Python script for the second optimization problem "Operation and investment optimization". The expanded code of the "Load Model" implemented in the Python Script developed in the ELMAR project was not allowed to publish in this master thesis. The expanded code, as described in section 5, including the calculation of hydrogen demand and charge power demand for full-electric and plug-in hybrid ships. Furthermore, all the plots and data sorting of the day-ahead price from Nord Pool is not included in this appendix.

```

    model = pyo.ConcreteModel()

# Sets
N = 8760                        # number of hours simulated for
M= math.ceil(N/744)             # Months based on the number of hours simulated for
print(M)
model.T = pyo.RangeSet(0,N-1)
model.M = pyo.RangeSet(0, M-1)


# Parameters from the Load model
P_pv = PVPower[0:N]                 # Produced power from the PV modules
P_sh = ShorePower[0:N]              # Shore power demand per hour
P_ch = ChargeDemand[0:N]            # Charge power demand per hour
H_demand = HydrogenDemand[0:N]      # Hydrogen demand per hour

# Economic parameters
C_el = Cel_tot[0:N]             # Day-ahead prices + energy tariff (NOK/kWh)
model.C_storage =5450           # Hydrogen storage (NOK/kg)
model.C_ely = 6400              # Elctrolysis (NOK/kWh)
model.C_trafo = 240             # Transformer (NOK/kWh)
Fixed_el_price = Fastledd[0:M]     # Fixed cost per month  (NOK)
C_peak = C_ndarry[0:M]             # Grid tariff per month  (NOK/kW)

#System parameters
H_storage_max = 0               # Start hydrogen storage capacity (kg)
H_storage_min = 0               # Min hydrogen storage capacity (kg)
H_storage_start = 0             # Start value of the hydrogen storage level (kg)
H_storage_end = 0               # End value of the hydrogen storage (kg)
P_ely_max = 0                   # Start capacity of the elctrolysis (kW)
P_ely_min = 0                   # Min capacity of the elctrolysis (kW)
P_trafo_max =0                  # Start capacity of the transformer (kW)
n_ely = 1/50                    # Efficiency factor of the electrolysis divided by the LHV of hydrogen (kg/kWh)

# initialize the parameters to the model:
model.C_peak = pyo.Param(model.M, initialize=C_peak, within = pyo.NonNegativeReals)
model.H_storage_max = pyo.Param(initialize=H_storage_max)
model.H_storage_min = pyo.Param(initialize=H_storage_min)
model.H_storage_start = pyo.Param(initialize=H_storage_start)
model.H_storage_end = pyo.Param(initialize=H_storage_end)
model.P_el_max = pyo.Param(initialize=P_el_max)
model.P_el_min = pyo.Param(initialize=P_el_min)
model.n_el = pyo.Param(initialize=n_el)
model.P_trafo_max = pyo.Param(initialize=P_trafo_max)
model.P_sh = pyo.Param(model.T, initialize=P_sh)
model.P_ch = pyo.Param(model.T, initialize=P_ch)
model.H_demand = pyo.Param(model.T, initialize=H_demand)
model.C_el = pyo.Param(model.T, initialize=C_el)
model.P_pv = pyo.Param(model.T, initialize=P_pv)
```

```
model.Fixed_el_price = pyo.Param(model.M, initialize=Fixed_el_price)


# Define variables
model.P_grid_b = pyo.Var(model.T, within=pyo.NonNegativeReals)
model.P_peak = pyo.Var(model.M, within=pyo.NonNegativeReals)
model.P_load = pyo.Var(model.T, within=pyo.NonNegativeReals)
model.H_storage_level = pyo.Var(model.T,  within=pyo.NonNegativeReals )
model.P_hy = pyo.Var(model.T, within=pyo.NonNegativeReals)


#Extra variables
model.hyd_cap = Var(within=pyo.NonNegativeReals)
model.ely_cap = Var(within=pyo.NonNegativeReals)
model.trafo_cap= Var(within=pyo.NonNegativeReals)

# Objective function
def obj_function(model):
    return sum(model.C_el[t]* model.P_grid_b[t] for t in model.T)
        +sum(model.C_peak[m] * model.P_peak[m] +Fixed_el_price[m] for m in
        model.M) + model.hyd_cap * model.C_storage + (model.ely_cap *
        model.C_ely)+  model.C_trafo* model.trafo_cap


model.obje = pyo.Objective(expr=obj_function, sense=pyo.minimize)




# Constraints

def power_balance(model, t):
    return model.P_grid_b[t] + model.P_pv[t] == model.P_load[t]
model.Power_balance = pyo.Constraint(model.T, rule=power_balance)


def capacity_in_grid(model, t):
   return model.P_grid_b[t] <= model.P_trafo_max + model.trafo_cap
model.cap_grid = pyo.Constraint(model.T, rule=capacity_in_grid)


def peak(model,t):
if t <= 744:  # Jan
     return model.P_peak[0] >= model.P_grid_b[t]

 elif 745 <= t <= 1416: # Feb
     return model.P_peak[1] >= model.P_grid_b[t]

 elif 1417<= t <= 2160: # Mar
     return model.P_peak[2] >= model.P_grid_b[t]

 elif 2161<= t <= 2880: # April
     return model.P_peak[3] >= model.P_grid_b[t]

 elif 2881<= t <= 3624: # May
     return model.P_peak[4] >= model.P_grid_b[t]

 elif 3625<= t <= 4344: # June
     return model.P_peak[5] >= model.P_grid_b[t]

 elif 4345<= t <= 5088: # July
     return model.P_peak[6] >= model.P_grid_b[t]

```

```
 elif 5089<= t <= 5832: # Aug
     return model.P_peak[7] >= model.P_grid_b[t]

 elif 5833<= t <= 6552: # Sept
     return model.P_peak[8] >= model.P_grid_b[t]

 elif 6553<= t <= 7296: # Oct
     return model.P_peak[9] >= model.P_grid_b[t]

 elif 7297<= t <= 8016: # Nov
     return model.P_peak[10] >= model.P_grid_b[t]

 elif 8017<= t <= 8760: # Dec
     return model.P_peak[11] >= model.P_grid_b[t]

 else:
     return pyo.Constraint.Skip

model.Peak = pyo.Constraint( model.T, rule = peak)



def electrolyse_max(model, t):
    return model.P_hy[t] <= model.P_ely_max + model.ely_cap
model.Electrolyse_max = pyo.Constraint(model.T, rule=electrolyse_max)


def electrolyse_min(model, t):
    return model.P_ely_min <= model.P_hy[t]
model.Electrolyse_min = pyo.Constraint(model.T, rule=electrolyse_min)



def hydrogen_storage_max(model, t):
    return model.H_storage_level[t] <= model.H_storage_max + model.hyd_cap
model.Hydrogen_max = pyo.Constraint(model.T, rule=hydrogen_storage_max)


def hydrogen_storage_min(model, t):
    return model.H_storage_min <= model.H_storage_level[t]
model.Hydrogen_min = pyo.Constraint(model.T, rule=hydrogen_storage_min)


def hydrogen_level(model, t):
    if t == 0:
        return model.H_storage_level[t] == H_storage_start
    elif t == 8759:
        return model.H_storage_level[t] == H_storage_end
    else:
        return model.H_storage_level[t] == model.H_storage_level[t - 1] +
            (model.P_hy[t - 1] * model.n_el) - model.H_demand[t - 1]

model.Hydrogen_level = pyo.Constraint(model.T, rule=hydrogen_level)


def total_power_load(model, t):
    return model.P_load[t] == model.P_hy[t] + model.P_sh[t] + model.P_ch[t]
model.Tot_load = pyo.Constraint(model.T, rule=total_power_load)


# solving the problem
solver = 'gurobi'
opt = pyo.SolverFactory(solver, load_solution=True)
```

```
results = opt.solve(model, load_solutions=True)

##################################################################
# Calculation for duration curves#
##################################################################
day1 = []
for m in model.M:
    d1 = model.P_peak[m].value
    day1.append(d1)

total_Energy_demand = []
for t in model.T:
    load = model.P_load[t].value
    total_Energy_demand.append(load)

Total_Energy = sum(total_Energy_demand)
Utilization = Total_Energy / max(day1)
Load_factor = Utilization/N

p_sh = []
p_hy = []
p_ch = []
for t in model.T:
    ele = (model.P_sh[t])/1000          # Value in MW
    p_sh.append(ele)
    hy = (model.P_hy[t].value)/1000     # Value in MW
    p_hy.append(hy)
    ch = (model.P_ch[t])/1000           # Value in MW
    p_ch.append(ch)

Tot_P_hy = sum(p_hy)
Tot_P_sh = sum(p_sh)
Tot_P_ch = sum(p_ch)

P_load_sorted = np.sort(total_Energy_demand)[::-1]
P_sh_sorted=np.sort(p_sh)[::-1]
P_hy_sorted=np.sort(p_hy)[::-1]
P_ch_sorted=np.sort(p_ch)[::-1]
```

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